PECO Statement No. 1:

Direct Testimony of Nicole L. LeVine

PECO ENERGY COMPANY
STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

DIRECT TESTIMONY

WITNESS: NICOLE L. LEVINE

SUBJECTS: PECO'S ELECTRIC OPERATIONS; OVERVIEW OF PECO'S RATE FILING; PECO'S CAPITAL INVESTMENTS; CUSTOMER SERVICE, SAFETY, SECURITY, ENVIRONMENTAL PROGRAMS; FULFILLMENT OF 2021 RATE CASE COMMITMENTS; ECONOMIC DEVELOPMENT, COMMUNITY SUPPORT, AND DIVERSITY; AND MANAGEMENT PERFORMANCE

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DIRECT TESTIMONY
OF
NICOLE L. LEVINE

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Nicole L. LeVine. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Vice President and Chief Operating Officer. In that capacity, I lead PECO's electric and natural gas distribution and transmission operations. These operations include construction and maintenance, engineering and technical services, investment strategy, safety, environmental, training, fleet, real estate and facilities, new business, and customer operations. These functions, in turn, are staffed by approximately 2,731 craft, professional, and support employees. I also ensure that the operating groups are well integrated and focused on safety, reliability, customer satisfaction, and diversity, equity, and inclusion.

3. Q. Please summarize your prior professional experience.

A. During the past 20 years, I have held numerous positions within PECO and its parent Exelon Corporation. I will highlight a few of my more recent positions. Before becoming Chief Operating Officer of PECO, I served as Vice President, Electric Operations at PECO for over four years. In this role, I oversaw the daily operations of PECO's electric distribution system, including management of the

Company's Distribution System Operations and Construction and Maintenance organization. Prior to that, I served in various leadership roles at PECO, including Vice President of Technical Services and held various roles of increasing responsibility in PECO Gas Operations, Field Operations, Transmission & Substations, and Exelon Utilities.

4. Q. What is your educational background?

A. I earned my Bachelor of Science degree in civil engineering from the University of Delaware.

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

A. The several purposes of my direct testimony are to: (1) generally describe PECO's electric distribution operations; (2) provide an overview of this rate filing, including an introduction of the other witnesses who will present testimony in support of PECO's case-in-chief; (3) explain PECO's capital investment process and to identify the types of projects that comprise PECO's claimed future test year ("FTY") and fully projected future test year ("FPFTY") plant additions; (4) describe various measures by PECO to ensure system reliability; (5) discuss PECO's customer service operations and several additional programs to help our customers save energy and use new energy technologies; (6) describe measures taken by the Company with respect to safety, security, and its environmental impact; (7) discuss PECO's fulfillment of the commitments made by the Company as part of the settlement approved by the Pennsylvania Public Utility Commission (the "Commission") in PECO's 2021 electric base rate proceeding; (8) describe PECO's community work and support for economic and workforce

development and diversity, equity and inclusion; and (9) address PECO's overall management performance in relation to the factors identified in Section 523 of the Public Utility Code.

II. DESCRIPTION OF PECO'S ELECTRIC OPERATIONS

6. Q. Please provide an overview of PECO's electric distribution operations.

A. PECO is the largest combined electric and natural gas utility in Pennsylvania. In addition to the approximately 1.7 million electric customers we serve, PECO provides natural gas service to over half a million customers. PECO's electric service region is located throughout a 2,100 square-mile area in southeastern Pennsylvania. The Company's electric service territory comprises all or portions of Bucks, Chester, Delaware, Montgomery, Philadelphia, and York Counties and includes a total population served of approximately 4.1 million people.

7. Q. What services does PECO offer its electric customers?

A. PECO makes available electric distribution service and electric generation supply on an unbundled basis. In addition to those customers who have exercised their option to procure their own electric generation supply service and pay PECO for delivery (i.e., distribution) service only, the Company, as the default service provider, procures and delivers power to the homes or places of business of residential, commercial, and industrial customers not receiving service from an electric generation supplier ("EGS") or who return to default service after being served by an EGS that becomes unable or unwilling to serve its customers. In addition to general service, and as set forth in the Company's electric tariff, qualifying customers can avail themselves of a variety of outdoor-lighting,

interruptible, and other services. PECO also provides a variety of programs to assist customers with their energy costs, including a Customer Assistance Program ("CAP") for low-income customers and a wide range of energy efficiency programs for all residential, small commercial, and large commercial and industrial customers through PECO's Energy Efficiency and Conservation ("EE&C") programs.

8. Q. How does the type of electric customers PECO serves break down by major customer classification?

A. As of December 31, 2023, we served 1,535,927 residential customers, 166,660 small commercial and industrial ("C&I") customers, and 3,132 large C&I customers.

9. Q. What are the major assets and facilities that PECO utilizes to provide electric service to its customers?

A. PECO is the largest combined electric and natural gas utility in Pennsylvania. To provide electric service to its customers, PECO operates and maintains approximately 9,700 miles of underground distribution cable, approximately 13,000 miles of aerial distribution lines, and approximately 1,092 miles of higher-voltage transmission lines. In addition, we operate and maintain 440 power substations.

Generally speaking, this infrastructure is a mix of reliable older and newer facilities and equipment. Consequently, a high level of expertise in a variety of areas, as well as significant capital investment, are required to maintain and

operate all of PECO's plant and equipment and to provide the service, reliability, and modern electric grid capabilities that our customers expect.

III. OVERVIEW OF RATE FILING

10. Q. Please summarize the relief that PECO is requesting through this rate filing.

A. PECO has requested an annual overall electric rate increase of approximately $464 million. PECO is also proposing a one-time credit of $64 million, resulting in a net electric rate increase of $399 million in 2025.

As required by the Public Utility Code, PECO's proposed tariff has been filed on 60 days' notice and, therefore, bears an effective date of May 27, 2024. However, we recognize that our filing will likely be suspended and investigated.

11. Q. Why is PECO requesting a rate increase at this time?

A. Our last electric base rate filing was made in 2021. Since rates were established in that case, PECO has continued to make substantial investments in new and replacement utility plant to ensure that our customers can continue to receive the safe and reliable service they have come to expect. Indeed, between January 1, 2023 and December 31, 2025, the end of the FPFTY, we will have invested over $3.5 billion in additional electric distribution plant.

Much of this investment is focused on maintaining and improving our system reliability, upgrading and replacing obsolete equipment, and advancing our informational technology and communications systems, which all have positive benefits for our customers. We also make substantial infrastructure investments to serve new customers as well as customers whose electric energy needs are

growing through new operations or services, such as electric vehicle charging stations. Since the COVID-19 pandemic, a significant portion of the workforce in the region we serve also now works at home or in hybrid arrangements, necessitating robust grid reliability and resilience throughout our entire distribution system.

At the same time, while we continue to add new customers and modernize our distribution system infrastructure, our overall sales are expected to be nearly flat in large part due to our aggressive pursuit of energy efficiency and conservation through the EE&C programs implemented in compliance with Pennsylvania's Act 129 of 2008 ("Act 129").

We face significant cost increases in a variety of areas that are not within our control. While Company witness Marissa Humphrey in PECO Statement No. 2 discusses inflation and other financial costs, we also experience numerous other operational cost increases that cannot be avoided. Even as we plan for and implement capital investments, we must manage a variety of global and domestic supply chain challenges that continue to impact equipment costs and the availability and lead time for certain materials, including transformers critical for our system. We are constantly evaluating options for alternatives and working with our business partners and material vendors to develop and implement long-term strategies to reduce project timelines and duration. As we continue to invest in our infrastructure, we also continue to ensure that we are adequately staffed to provide our customers with a great experience.

In addition, even with increased efforts focused on vegetation management across our system, costs associated with certain storms (such as Hurricane Ida) have resulted in higher costs for restoration and repairs. Such costs are very difficult to predict given the nature of storms, and we are proposing a new Storm Reserve Account in this proceeding described by Company witness Michael J. Trzaska in PECO Statement No. 3.

As Ms. Humphrey details, despite the rate increase we are proposing, customer affordability remains a critical priority for PECO, and we are continuing to expand our customer assistance programs to help minimize the impact of higher rates. As Mr. Trzaska explains, the Storm Reserve Account will enable PECO to recover its actual storm damages – neither more nor less – and ensure that customers are only paying for actual storm costs. Furthermore, we continue to seek out new sources of funding for capital investment – including our efforts to obtain funding from the U.S. Department of Energy's Grid Resilience and Innovation Partnership ("GRIP"), where we have been selected to negotiate an award for up to $100 million for grid modernization. All funding received through the GRIP program will reduce the overall revenue requirement to serve our customers and add to the capital and infrastructure investments we make every year that create and maintain thousands of jobs in the communities we serve.

12. Q. What has PECO done to control expenses?

A. As in past years, we have continued to carefully manage our operations and maintenance ("O&M") expenses. As discussed by Ms. Humphrey, PECO's

projected annual O&M growth rate since 2022 is 25% lower than the recent average 5.5% inflation increase in the Consumer Price Index. The Company's projected O&M growth rate is 4.1% when adjusted for storms and "make-ready" work requested by third parties.

13. Q. Please identify the witnesses providing direct testimony on behalf of PECO in this proceeding.

A. In addition to myself, the following witnesses will be responsible for presenting PECO's case-in-chief:

Marissa Humphrey (PECO Statement No. 2) is Senior Vice President, Chief Financial Officer and Treasurer of PECO. Ms. Humphrey discusses PECO's need for rate relief and our efforts to minimize customer costs and bills. Ms. Humphrey also provides an overview of PECO's principal accounting exhibits; discusses PECO's budgeting process; describes the services that PECO receives from affiliated entities and the estimated cost of those services during the FPFTY; and discusses the impacts of the Corporate Alternative Minimum Tax.

Michael J. Trzaska (PECO Statement No. 3) is a Principal Regulatory and Rates Specialist at PECO. Mr. Trzaska sponsors PECO Exhibits MJT-1, MJT-2, and MJT-3, which set forth PECO's revenue requirement for the FPFTY ending December 31, 2025, FTY ending December 31, 2024, and historic test year ("HTY") ended December 31, 2023, respectively. He supports PECO's rate base, revenue, operating expense and tax claims, as well as the Company's proposed

Storm Reserve Account, and describes the customer credits of fiber network fees and COVID-19 pandemic benefits.

Caroline Fulginiti (PECO Statement No. 4) is Vice President and Assistant Controller of Exelon. Ms. Fulginiti describes PECO's accounting processes, supports the assignment and allocation of common costs between PECO's electric and gas operations, and explains the development of the depreciated original cost of the Company's utility plant in service and its claim for annual depreciation expense.

Paul R. Moul (PECO Statement No. 5) is the Managing Consultant of P. Moul & Associates, Inc. Mr. Moul presents testimony concerning the rate of return that PECO should be afforded an opportunity to earn on its rate base. He supports PECO's claimed capital structure ratios, its embedded costs of debt, and its requested equity allowance.

Tamara J. Jamison (PECO Statement No. 6) is Senior Manager, Revenue Policy at PECO. Ms. Jamison presents an unbundled, fully allocated customer class cost of service study ("COSS").

Joseph A. Bisti (PECO Statement No. 7) is a Manager of Rate Analysts at PECO. Mr. Bisti presents PECO's proposed tariff rates and explains how the results of Ms. Jamison's COSS, as well as the consideration of other factors, were utilized in the rate design process.

Megan A. McDevitt (PECO Statement No. 8) is Senior Manager, Retail Rates at PECO. Ms. McDevitt discusses proposed changes and clarifications to PECO's electric service tariff.

Steven J. DeMott (PECO Statement No. 9) is PECO's Senior Manager, Strategic Planning. He discusses PECO's proposal to extend its pilot incentive programs for electric vehicle ("EV") charging and the Company's proposal to extend and modify its Electric Vehicle Fast Charging Pilot Rider.

Jacqueline F. Golden (PECO Statement No. 10) is the Director of Customer Financial Operations at PECO. Ms. Golden discusses the Company's proposed recovery of CAP costs, other universal service programs, enhancements to the Company's Matching Energy Assistance Fund ("MEAF"), and expanded outreach and education plans for low to moderate income customers.

IV. PECO'S CAPITAL INVESTMENTS

14. Q. How does PECO determine its annual capital investment requirements?

A. PECO's capital investment plan begins with a detailed budgeting and long-range plan development process. A key goal of that process is to integrate and align capital investments with PECO's strategic operational goals and regulatory and financial plans. The mix of capital investment needs can change from year to year and is the product of a variety of factors, including trends in the housing market, emergent operational constraints, local municipality workloads, and, most importantly, the condition of existing facilities.

Projects requiring a capital investment of over $1.5 million ("Major Projects") are subject to an additional, rigorous committee review process which includes senior management control of project scope and contract strategy. The primary goals of the process are to ensure that:

(1) the technical merits of each Major Project are balanced with the economic benefits and goals of the Company;

(2) Major Projects are properly researched, developed, planned, reviewed, and authorized by senior management before significant resources are committed or expended; and

(3) decision points for consideration and approval of any additional funds are established as the details of Major Projects evolve.

All of these capital investment processes work together to ensure that PECO's investments fully support safety, reliability, and customer service goals as well as achieve an optimal operational efficiency.

15. Q. What are PECO's primary categories of capital investment?

A. Our capital investment requirements are evaluated on a functional level and are placed primarily into categories of corrective maintenance, system performance, capacity expansion, facility relocation, new business, information technology ("IT"), and customer operations.

Corrective Maintenance is work in support of maintaining the existing electric distribution network, such as replacing or upgrading utility poles, reclosers, cable and/or wire. These projects can be identified as a result of patrols, inspections performed, or storms and outage causing events (i.e. pole hits, tree limbs, etc.).

System performance projects are risk modeled and evaluated to prioritize the projects for replacements. These projects are ranked based on certain criteria, including but not limited to age, failure rates, customer complaints, cost to replace versus cost to repair, condition of infrastructure, and environmental factors. Of particular note are system reliability and resiliency improvements under the Company's Customers Experiencing Multiple Interruptions ("CEMI"), Aerial Infrastructure Resiliency, and Underground Cable Replacement programs that all target replacement of infrastructure with higher risk profiles based on field observations and a review of performance metrics (for example, replacing underground cabling with underground cabling in conduit for much longer operational life).

Capacity expansion projects relieve capacity constrained areas, which allows for the addition of new customers and increases the ability of those feeders to handle the interconnection of additional customer-owned solar facilities. Facility relocation projects move electric facilities away from conflicting township and state road improvements.

New business projects support residential and commercial customer requests for new electric service, upgrades of existing service, and the relocation of electric facilities. We are seeing significant new business demand, with new high-rise buildings in Philadelphia, new town home developments in suburban communities, and other new construction projects. Our existing customers whose operations are expanding (e.g., warehouses) also need a variety of infrastructure

upgrades, and we are addressing rising demand for electric vehicle charging stations at businesses.

In the area of IT infrastructure, many of our capital projects drive operational improvements and efficiencies, reduce risk and increase reliability, and strengthen cybersecurity. For example, our One Mobile Dispatch System is a strategic initiative for PECO to enable digitization of field work activities and eliminate manual processing, and our Enterprise Asset Management replacement enables improved asset management, work order development, and work management. The Company is also investing in its upgraded Advanced Distribution Management System, which will provide distribution operations with state-of-the-art modernized tools to improve reliability, resiliency, and customer experience during storms, increase operational efficiency, and create a coordinated platform for implementation and deployment of the new operational capabilities that our customers want the distribution system to provide.

A primary area of our capital investment relating to customer operations covers the design, development, implementation, lifecycle upgrades and replacements, and security of customer facing systems, as well as the development and implementation of web tools, such as outage tools and mobile app technologies, so customers can easily access PECO customer systems and information through multiple channels. These are individual projects that help the Company create and improve the technology PECO customers use to access account and outage information; enroll in assistance programs; make start, stop, and move requests;

receive usage data, and receive and pay bills, which I will describe later in my testimony.

We are also investing in Customer Flight Path ("CFP") projects, which improve the availability of customer products and the reliability of the underlying platforms. These projects consist of enhancing digital self-service options and offering personalized solutions that meet customer needs, improve communications during power outages, and help promote and maintain affordability. Associated with these capital projects are O&M costs in order to put these investments into service for customer benefit.

16. Q. How do capital investments in distribution system infrastructure relate to PECO's Long-Term Infrastructure Improvement Plan ("LTIIP")?

A. Many of our capital investments are made in coordination with the goals and requirements of PECO's LTIIP, which the Commission approved on November 19, 2020. In that proceeding, the Commission approved PECO's plans to spend $1.36 billion on targeted reliability projects to prevent storm-related outages, replace electric cable, and replace or retire substation equipment and small substations.

These LTIIP investments are in addition to the capital spending associated with the Company's proposed rate increase but involve many of the same types of capital work and these investments in the aggregate are necessary to meet our targeted improvements. For example, as reflected in PECO's Commission-approved LTIIP, PECO's long-term goal for its CEMI programs is a 25%

reduction in the frequency of interruptions for the improved areas and circuits by 2026. By aligning our "baseline" capital investments discussed in this proceeding and our planned LTIIP expenditures, we are able to improve reliability and replace aging infrastructure more efficiently and therefore at a lower overall cost to customers.

17. Q. Is PECO investing in technology to support its grid investments?

A. Yes, we are investing in a number of innovative technologies that enhance our ability to identify critical areas for investment. For example, we are now deploying aerial drone technologies for construction planning and design, storm damage assessment, post-construction audits, transmission line patrols, and other construction-related activities. Drones are also used to gain situational awareness in hard-to-access areas during various electric operations.

We are also evaluating the effectiveness of an underground, submersible automatic transfer switch that provides increased reliability by automatically transferring from primary to alternate supply in the event primary supply is interrupted. In addition, we have piloted the use of aerial communicating Faulted Circuit Indicators which enhance the situational awareness of our distribution system operators to reduce patrol times with an opportunity to reduce outage durations. Both of these technologies have substantial potential to further reduce the duration of customer interruptions when those interruptions occur.

18. Q. Please describe, in broad terms, the types of plant additions that PECO expects to place in service during the course of the FTY and FPFTY.

A. PECO's FPFTY and FTY plant additions are itemized by functional area and by FERC account in PECO Statement No. 3, the direct testimony of Mr. Trzaska, Exhibits MJT-1 (Schedule C-2) and MJT-2 (Schedule C-2), for the FPFTY and FTY, respectively.

In summary, our 2024 capital budget calls for approximately $1.3 billion of plant additions in new distribution facilities, including the portions allocated to distribution from general and common plant additions. For 2025, we have budgeted approximately $1.2 billion of plant additions in new distribution facilities, including the portions allocated to distribution from general and common plant.

19. Q. In your opinion, is all of the plant that PECO has included in its rate base claim needed in order to provide safe and reliable electric service?

A. Yes, it is. The assets included in PECO's rate base are, or by the end of the FPFTY will be, in service and used by PECO to provide safe and reliable electric service to customers.

V. SYSTEM RELIABILITY

20. Q. What steps has PECO taken in recent years to ensure system reliability?

A. Each year, PECO invests heavily in its electric system to increase reliability and to enhance the quality of the service it provides. Nationally, our system is in the first quartile when benchmarked against similar utilities in the electric power

industry, and our performance under Pennsylvania's reliability metrics is consistently strong. The needs and expectations of our customers for reliable electric service are evolving as more individuals, businesses, and communities plan for and manage hybrid work arrangements and increasingly use electric vehicles and other technologies that are dependent upon a reliable, resilient, and flexible electric distribution grid that is always on, 24 hours a day, seven days a week.

In order to identify, develop, and prioritize reliability-related investment in electric infrastructure, the Company uses a risk-based approach. PECO's risk analysis reflects the accepted definition of risk as the product of probability and impact, where "probability" is the likelihood that an event may occur, and "impact" is a measure of the adverse consequences such an occurrence would create.

In conjunction with a risk-based approach, PECO continues to adapt reliability efforts to match evolving customer expectations. We also focus on traditional reliability metrics, such as System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and System Average Interruption Duration Index ("SAIDI"), as well as additional measures such as CEMI and geographical areas. This additional focus facilitates targeting our investments on areas that may be experiencing outage issues that are not captured under traditional metrics linked to "average" numbers of interruptions or outage duration.

In recent years, PECO performed many targeted system enhancements and corrective maintenance projects to continue its strong electric reliability performance so that customers experience, on average, less than one service interruption per year outside of major storms. Highlights of our reliability-related investments and work include the following activities:

CEMI Area Infrastructure.[1] We focused our distribution system infrastructure investments on areas and circuits where customers experienced a higher number of sustained interruptions, and our investments resulted in an average reduction of 36% in the frequency of interruptions for those customers between the years 2021-2023.

New Substations, Transformers, and Converted Distribution Facilities. We retired several large substations and converted surrounding distribution facilities with their transformers to operate at higher (13 kV or 34 kV) voltages to reduce losses, improve voltage regulation, and facilitate more interconnection of customer-owned solar facilities. Retirements included 37-unit substations and one building substation, some of which had been subject to flooding during the 2021-2023 period.

Replacement of Underground Cable and Poles. From 2021-2023, we replaced 501.4 miles of underground residential development ("URD") cable and 89.2 miles of mainstem cable that had exhibited a rising trend of failure rates, with a

[1] CEMI is an index that tracks the number of customers that have experienced more than a specific number of interruptions in a given period. PECO has established a threshold of four interruptions per year.

resulting reduction in customer interruptions. We also replaced over 5,600 poles with modern equipment designed to withstand higher winds and snow/ice loading. The strength of these new installations will improve reliability in normal weather conditions and provide enhanced resistance to storm related damages.

Increased Distribution System Automation. We continued to identify circuits throughout PECO's service territory as candidates for priority reliability improvements and installation of reclosers, sectionalizers, and distribution automation to pinpoint problems and quickly restore service. Between 2021 and 2023, PECO installed 603 of these devices and avoided over 2.2 million customer interruptions over that period. Our integration of smart technology, combined with information from advanced metering infrastructure ("AMI") meters, communication infrastructure, and the Company's upgraded geographic information and distribution management systems, improves situational awareness, operations, safety, and communication outreach during outages.

Vegetation Management. In 2020, PECO began the transition from a five-year cycle to a four-year cycle for vegetation-related preventative maintenance work on approximately 13,000 miles of aerial distribution lines, which ensures more frequent inspection and control of vegetation that could cause outages. This has helped to address risks associated with tree in-growth, vines, and bamboo. Our distribution and transmission vegetation management programs are operated in conjunction with data-driven corrective maintenance and inspection programs that focus on enhanced vegetation clearance to improve reliability, as well as the removal of dead and declining trees to improve performance in areas where

multiple tree-related interruptions have occurred (especially in storms). In addition, PECO implemented a new vegetation management program to aggressively address selected circuit segments with poor performance attributable to vegetation. This multi-year program addresses problematic areas with enhanced design applications such as aerial cables, tree wire, and armless construction and associated vegetation management. Between 2021 and 2023, PECO addressed 80 selected circuit segments with poor performance attributed to vegetation. These projects were effective and customers experienced fewer interruptions due to vegetation.

21. Q. Ms. LeVine, please describe PECO's reliability performance since its last base rate proceeding.

A. Our customers are experiencing the benefits of the reliability and performance improvements we continue to achieve since our last rate case. As a result of the Company's investments, including the projects I described above, PECO outperformed the Commission's target levels for SAIFI and SAIDI.

PECO's SAIFI for the three-year (2021-2023) period was 0.78 interruptions, compared to the benchmark of 1.23 interruptions and the three-year standard of 1.35 interruptions. Over this period, PECO's average number of service interruptions decreased by 15%, from 0.88 interruptions in 2021 to 0.75 interruptions in 2023. Within the industry, PECO continues to rank in the top quartile when compared to our peers across the country.

For SAIDI, PECO's 2021-2023 three-year average was 113 minutes, compared to the benchmark of 138 minutes and the three-year standard of 167 minutes. Notably, PECO's SAIDI performance improved significantly in 2023 compared to 2021, with SAIDI dropping from 165 minutes in 2021 to 103 minutes in 2023 – a 38% reduction. When benchmarked with our industry peers, PECO's SAIDI performance also ranks in the top quartile.

The Commission also measures PECO's CAIDI. This three-year performance standard only allows a deviation of 10% from the reliability index benchmark. The 2021-2023 three-year average restoration time for PECO customers who lost power was 141 minutes (2021-2023) compared to the benchmark of 112 minutes and the three-year standard of 123 minutes. While several storms caused PECO to miss the Commission's defined CAIDI standards, our data for 2023 demonstrates that the average time customers are without power has declined by 26% from 2021, and PECO's CAIDI continues to rank in the top quartile of our industry peers.

22. Q. Does PECO have a commitment to continue to maintain and enhance reliability?

A. Absolutely. Over the next two years (2024-2025), PECO will continue to focus on storm hardening and resiliency, and plans to invest approximately $1.45 billion to improve the reliability of its electric distribution system. These strategic investments will help prevent customer outages, modernize the electric grid, and reduce the impact of extreme weather on PECO's electric infrastructure. The Company's reliability improvement programs in 2024 and 2025 will include:

Storm Hardening and System Enhancement. PECO will continue to replace aging equipment and upgrade facilities to the latest construction standards for improved distribution system reliability and resiliency to storms. PECO also plans to install at least 181 reclosers in 2024 and perform other system enhancement work, which will reduce the number of customers and circuits affected by outage events and mitigate customer interruptions. PECO plans to install at least 50 reclosers in 2025. The accelerated installation of reclosers in problematic circuit sections will positively impact system SAIFI.

Underground Cable Replacement. Between 2024 and 2025, PECO will replace at least 80 additional miles of mainstem cable and nearly 600 miles of URD cable and upgrade associated equipment to the latest construction standards, including looping any radial URD cable.

Aerial Infrastructure Resiliency. PECO will replace aerial infrastructure to proactively address those facilities that are vulnerable to failures caused by age-related degradation, normal environmental exposure, and ordinary wear and tear – factors that also increase the probability of storm-related damage. For example, the Company will install insulated aerial wire arranged in a special configuration to better withstand tree contact. PECO has already completed some installations in areas with dense tree coverage in an effort to strengthen its system against storms, increase reliability, and reduce outages. In addition, between 2024 and 2025, PECO will replace approximately 11,200 poles that were installed before 1965.

PECO's Top Priority Circuit Program. PECO analyzes and completes reliability enhancements on at least five percent of the system's worst performing circuits on an annual basis. Improvements include installing reclosers for distribution automation, identifying and repairing issues through visual thermographic inspections, increasing vegetation management activities, installing and upgrading fuses, and replacing cable and other equipment.

Targeted CEMI Areas. PECO will continue to address CEMI areas and circuits by reinforcing circuits with construction that can better withstand tree contact and storms, as well as adding automated switching flexibility. These investments will reduce the frequency of interruptions for those customers.

Distribution Automation. PECO will continue to add distribution automation equipment to its circuits, applying the latest technologies to reduce the impacts to customers when outages do occur.

Substation Retirements. In 2024 and 2025, PECO will eliminate an additional 15 unit substations that are experiencing an increasing failure rate (i.e., those constructed forty or more years ago) and will upgrade all downstream low-voltage supply facilities to operate at higher voltages consistent with modern modes of operation. PECO will retire at least 40 unit substations between the Company's baseline investment and LTIIP plan. Nearly all of PECO's existing building substations that supply power to downstream facilities serving thousands of customers were constructed over fifty years ago and contain obsolete equipment. Over the next two years, PECO will retire an additional four building substations.

These retirements will enhance system resiliency, and the associated upgrades to the downstream facilities will support the adoption of clean energy resources in PECO's service area.

Targeted Vegetation Management. PECO will continue to address areas with poor reliability performance due to vegetation interference using enhanced designs and associated vegetation management. We will be building on the success to date of our vegetation management program and focusing on the circuit segments we identify as "worst performing" to maximize the value of the associated capital investment.

Priority Tree Removal. PECO will continue with its priority tree removal program. In certain portions of its distribution where the Company determines it to be appropriate, PECO will remove hazard trees and branches at risk of impacting the Company's distribution facilities.

Managing Emerald Ash Borer ("EAB"). An invasive insect, the EAB, has been present in PECO's service territory since 2012 and resulted in a significant increase in ash tree infestation and mortality that has been linked to power interruptions. PECO expects that the EAB infestation will continue to impact ash trees in its service territory through the end of the decade. PECO will continue its targeted focus on the removal of ash trees that are vulnerable to EAB infestation, threaten damage to PECO electric facilities, and increase the potential for equipment failures.

VI. CUSTOMER SERVICE AND PROGRAMS

23. Q. What steps has PECO taken in recent years to enhance the quality of the customer service it provides?

A. As I explained earlier, the expectations of our customers for a robust grid are evolving, and those expectations include customer service programs that are on-line, comprehensive, and dynamic. PECO's mobile application and its website, www.peco.com, now have many enhanced features that make it easier for a customer to sign up or move service, pay their bill with slide-to-pay by credit card or e-check, monitor usage, report an outage, and enroll in electronic billing, automatic payments, or budget billing. The Company also added a two-way outage text feature that enables customers to text "OUT" to report an outage and "STAT" to receive an outage status update.

On average, the Company sends over 30 million notifications and confirmations to our customers on a yearly basis. As of the end of 2023, PECO now has 1.15 million customers enrolled in "MyAccounts" (approximately 64% of customers), which is an increase from 1.03 million (approximately 59.5% of customers) in 2022 and directly reduces our customer operations costs. Most recently, PECO launched the Outage Tracker, which provides a status bar to visually track scheduled restoration progress. This was an important factor in enhancing our customer experience and overall customer satisfaction regarding our communications.

PECO upgraded the overall look and feel of its website and, consistent with applicable Web Content Accessibility Guidelines, updated its website's content to

be accessible to people with disabilities. Customers now also have the option to view webpages in English, Spanish, or Simplified Chinese. This feature provides multi-lingual customers the ability to quickly locate information about PECO's products and offerings.

We also added a variety of other features and capabilities, including a two-step customer verification process to improve customer account security and a "Welcome Back" feature for returning customers to access their program recommendations without re-entering information. We also added an "Assistance Finder" feature to aid customers with determining their eligibility to participate in energy assistance, financial, or energy efficiency programs. In the seven months since the launch of Assistance Finder in May 2023, nearly 1,000 customers have enrolled online in payment arrangements, budget billing, and due date extensions.

To enhance the quality of service and improve customer experiences, PECO shifted its focus to an approach we call "First Contact Resolution" ("FCR") so customers receive all the assistance they need on their first contact with the Company. Other initiatives include integrating the management of our outsourced call center into PECO's Customer Care Center (PECO's internal call center) to provide better alignment of quality guidelines, accountability, and leadership support. The Company also deployed a "Universal Agent" strategy whereby PECO customer service representatives ("CSRs") are trained to handle virtually all types of calls instead of targeted skill handling. This strategy enables CSRs to provide a more comprehensive call experience to customers and address each of the issues that led the customer to call PECO.

24. Q. What do the results of customer surveys indicate about the Company's customer satisfaction?

A. PECO's Customer Operations Department measures performance by, among other things, evaluating the results of customer satisfaction surveys. The Company uses a research firm, Escalent, that conducts surveys with customers about their experiences with the Company based on drivers that measure customer satisfaction. According to an analysis of Escalent's survey results for 2023, the Company's top drivers of satisfaction included reliability, customer service performance, and rates.

Customer Operations also evaluates Escalent's measurement of call center satisfaction – as well as the results of customer satisfaction surveys – to monitor and continuously improve the Company's interactions with customers when they contact the call center.

The customer survey results indicate that PECO customers have high levels of customer satisfaction across the various key drivers. At year-end 2023, PECO Residential customer satisfaction was at 87%, with 93% of customers satisfied with PECO's reliability, and 87% of customers stating that they believed it was easy to do business with PECO.

PECO also uses the J.D. Power Electric Utility Residential Customer Satisfaction Study to assess its performance. In the 2023 J.D. Power Electric Utility Residential Customer Satisfaction Study, PECO's Customer Satisfaction Index score was in the first quartile, with PECO ranking 2nd out of 17 companies in the

East Large Region. PECO ended the year with above average scores for power quality and reliability, communications, billing and payment, price, and customer care.

25. Q. How does the Company plan to continue improvement in customer satisfaction?

A. PECO recognizes its responsibilities to customers and seeks to invest in maintaining and improving how the Company provides premier customer service and how it interfaces with customers. Customer Operations has focused on improving the customer service component of this score through continuous improvement training of PECO's Customer Service Representatives, as well as incorporating more customer requested needs into the Company's interactive voice response system, web portal, My Account, and mobile apps.

26. Q. What direct customer benefits will PECO's additional investments in customer operations provide?

A. The CFP projects are designed to enhance the customer's online experience in areas such as billing and payments, managed account services, and start, stop, and move. Addressing critical customer information systems and expanding digital products and services can help meet customer expectations for reliable and personalized experiences.

27. Q. Please describe PECO's leadership in the area of energy efficiency customer programs.

A. Now in the third year of its fourth phase (2021-2026) of the EE&C Program, PECO's Ways To Save offerings continue to provide meaningful customer savings and comprehensive energy solutions for residential, non-residential, and low-income customers. During the first two years of the current EE&C Program, PECO helped our customers save more than 545,045 MWh.

PECO has gained consistent annual recognition for its excellence in program delivery with ENERGY STAR's Partner of the Year Sustained Excellence Award and ENERGY STAR's New Construction Market Leader Award for the past four years in a row for PECO's commitment to energy efficient new home construction. We continue to develop innovative programs, including an Act 129 Health and Safety Pilot for low-income customers resulting in $500,000 of health and safety services bridging to $1,300,000 in energy efficiency work being completed at no cost for these customers.

28. Q. Has PECO deployed advanced metering infrastructure ("AMI") meters in accordance with Act 129?

A. Yes. Under Act 129, PECO has deployed nearly 1.8 million electric AMI meters at customer premises. Despite many unforeseen challenges due to the COVID-19 emergency, the reading of those meters has consistently maintained first quartile performance (99.83%) since 2016 compared to the current industry average of 99.61%.

Consistent with previous years, customers are increasingly taking advantage of AMI meter capabilities. For example, since 2018, PECO customers with AMI meters utilized the interactive "My Usage" tool on the Company's website more

than 1.8 million times each year on average (through 2023). The remote connect and disconnect function of AMI meters has significantly improved customer-requested connect and disconnect services as well as credit-related disconnect and restoration. In 2023, 95% of customer-requested connects and disconnects were completed remotely and 98.5% of credit-related disconnects were completed remotely. This translates to an estimated 377,000 truck rolls avoided in 2023.

Deploying AMI technology across the Company's service territory has also enabled PECO to reduce restoration times during major storms. Improved AMI-based storm restoration efforts have avoided over 88,000 truck rolls during the past year (2023). For example, we have expanded our distribution automation devices from an installed base of 400 in 2017 to over 4,000, facilitating the automatic and remote re-routing of power during faults on the system to enhance performance and improve reliability. In 2023, PECO issued nearly 106,000 remote commands to distribution equipment to limit human contact with high voltage equipment and reduce restoration times, with a 99.9% success rate. Real time remote monitoring of distribution switches allows PECO to proactively identify failing distribution equipment and make repairs before it impacts electric service to customers. In addition, remote monitoring of over 525 capacitors has reduced field inspection cycles from every year to every four years. These devices also enhance the Company's ability to manage the communication system by allowing PECO to dedicate channels for unrestricted use during reliability events.

29. Q. Has the Company taken any recent actions with respect to distributed solar generation and other distributed generation ("DG") technologies?

A. Yes, the Company has implemented multiple initiatives to streamline the interconnection process, educate developers and potential solar/DG customers, and improve the overall experience for solar/DG customers. These efforts are managed by PECO's Green Power Connect ("GPC") department, which is currently staffed by 14 PECO employees dedicated to providing new and innovative ways to assist customers seeking to install solar energy systems and interconnect to the grid.

PECO established a solar collaborative in 2016, the first of its kind in the region, to discuss how to best advance solar options for PECO's customers. The stakeholders included solar developers, environmental groups, public officials, utilities, and competitive electric suppliers. The latest solar collaborative was held in August 2023 to hear from stakeholders and provide education on several PECO process improvement programs. In conjunction with the solar collaborative, the GPC team holds monthly webinars with customers who are in the Approved to Install status to educate them on the interconnection process and solar billing.

To further facilitate solar applications and solar interconnections, PECO created a Digital Solar Toolkit with an interactive viability map. With this toolkit, customers can see if their home or area can support solar or other distributed generation resources or if any system upgrades would be necessary.

From a technical standpoint, PECO has automated the technical analysis for a majority of Level 1 and smaller Level 2 solar applications by incorporating data analytics and machine learning techniques into the review process. This has led to a significant reduction in interconnection timelines. Additionally, PECO is currently undergoing an internal effort to update our technical interconnection requirements to better align with currently available technologies and the most recent industry standards. Once published internally, these updates will be incorporated into our publicly available technical documents to provide valuable technical guidance to customers looking to install solar and other DG.

In addition to the 200 amp single meter solution, PECO introduced a 320 amp solution in September 2022, and is expected to provide another solution for residential customers. Once that is accomplished, PECO will have a single meter solution for all residential customers. This makes it easier for contractors to connect solar to the distribution system which decreases timelines and reduces costs.

VII. SAFETY, SECURITY, AND ENVIRONMENTAL PROGRAMS

30. Q. What is PECO's record with respect to the safety of its employees?

A. Maintaining the highest standards for workplace safety is a top priority for the Company. A critical component of safety culture involves protecting our employees from serious injuries and fatalities ("SIFs"). To that end, PECO has embarked on initiatives to track incidents with potential for SIFs. The intent is to improve the effectiveness and efficiency of hazard recognition, prioritization, and control across the organization. Utilizing our Safety Classification Learning

Model ("SCL"), we have been able to identify high energy sources that could lead to serious injuries and put direct controls in place to reduce risk. As a result of these efforts, PECO finished 2022 and 2023 with zero High Energy Serious Injury or Fatalities ("H-SIFs"). An H-SIF is a high energy event with no direct controls utilized that resulted in an employee's serious injury or fatality. In 2024 and beyond, PECO will strive to continuously improve performance and foster a safety culture that engages the entire workforce to prevent accidents, injuries, and occupational illnesses.

31. Q. What actions is the Company taking regarding physical security and cybersecurity?

A. The ever-evolving threat landscape is of concern to our entire industry. In response, PECO has made significant investments in physical security as part of two separate programs. In 2015, PECO initiated the Facility Enhancement Program ("FEP") to enhance the physical security for operationally critical electric and gas assets. Additionally, in 2020, PECO began its Office and Support Facilities ("O&SF") program to enhance the physical security at offices and operation service centers. Both FEP and the O&SF program were designed to reduce unauthorized access to personnel, equipment, systems, and materials utilizing a defense in depth strategy. Both programs use a risk-based approach and tiering methodologies that analyze the criticality of each type of asset (Electric, Gas, and Office & Support Facilities) in order to prioritize investment. PECO tiers our assets based on factors such as, but not limited to, system impact, customer count, critical customers served, feeder number, etc. While the tier

dictates the protections implemented at each site, the protections are designed for the threats within the service territory that PECO operates.

In 2017, PECO expanded its resiliency efforts with the purchases of critical supplies and redundant equipment to facilitate timely system restoration following disruptions by natural or man-made events. Resiliency supplies and equipment are stored at separate facilities, strategically located, to restore service and minimize impacts to the over 1.7 million electric and gas customers throughout Southeastern Pennsylvania.

In implementing these security programs, we continue to forge strong partnerships among policymakers and regulators at the local, state, regional, and federal levels, customers, and utilities so that actionable information and intelligence can be shared, and best practices to defend against the changing threat landscape can continue to be identified to protect assets in a reliable and resilient manner. PECO annually participates in readiness drills/exercises, such as NERC's GridEx, to ensure we are prepared for potential threats. These types of exercises, which prioritize readiness and resiliency, encompass countless hours of planning and execution by dozens of PECO/Exelon personnel. PECO Security maintains partnerships and trainings with local law enforcement/first responders on the criticality of response and safety issues when responding.

In 2023, PECO hosted a bomb squad exercise which allowed personnel to drill and exercise their equipment in energized yards and provided in-person training to multiple police jurisdictions on possible substation threats, response, and

reporting. Additionally, PECO Security and Exelon Corporate Security maintain partnerships with local law enforcement and intelligence groups, including, but not limited to, the Electricity Information Sharing and Analysis Center, Delaware Valley Intelligence Center, and the PA Criminal Intelligence Center. Finally, PECO is an active participant in "Black Sky" exercises to test Pennsylvania's ability to respond to a large-scale disruption of power and utility services. The Black Sky initiative is coordinated by the Commission, the Governor's Office of Homeland Security, and the Pennsylvania Emergency Management Agency.

In addition to the Company's IT investments, PECO has programs to address cybersecurity risks and, along with its Exelon sister utilities, implemented an Operational Technologies ("OT") Security Governance Program ("OTSGP") to enhance existing cybersecurity measures. In accordance with this program, we properly identify and categorize OT assets and have developed an associated inventory of OT assets currently on our systems. OTSGP has also developed procedures to identify the specific cyber threat vulnerability to our asset inventory and the associated data connections, as well as remediation and mitigation strategies to protect PECO's interconnected system. Procedures have also been developed to manage access administration, data at rest and in transit between devices, and the sanitation and decommissioning of OT assets at their end of life. Safeguards have been put into effect for firewall utilization and malicious code detection. As part of this OTSGP, PECO will be implementing a transient cyber asset in 2024 – a disconnected system which scans and validates that new data

intended to integrate with internal systems is free of malicious code, allowing PECO's OT assets to remain in a completely disconnected environment.

As one of the nation's major critical infrastructure providers, the Company recognizes that the safety, reliability and security of our systems and facilities are a top priority. The Company utilizes a risk-based, intelligence-driven security approach to implementing a comprehensive set of cyber and physical security policies and procedures that implement controls, in line with the National Institute of Standards and Technology's Cybersecurity Framework. These controls effectively identify, protect, detect, respond to and recover from a spectrum of threats, mitigating the likelihood of successful attacks and their potential impacts. In addition, Exelon has mature and targeted policies and procedures to maintain compliance with the mandatory regulatory requirements defined within the NERC Critical Infrastructure Protection Reliability Standards, ensuring further protection of cyber assets critical to the safe and reliable operation of the Bulk Electric System from cyber and physical threats. These policies and procedures are reviewed annually by subject matter experts and revised as needed to address evolving threats. Regulated critical cyber assets are isolated within restricted networks, segmented from the enterprise IT environment and the internet, continuously monitored for malicious activity, and routinely evaluated for vulnerabilities.

32. Q. Ms. LeVine, please describe PECO's energy efficiency and environmental efforts regarding its own land, buildings, and emissions.

A. PECO's commitment to energy efficiency and environmental stewardship is also integrated in the Company's daily operations. PECO has established an environmental management system based on standards set forth in International Organization for Standardization 14001, which supports the development of performance-improvement goals and targets. Exelon, PECO's parent company, was recognized for its sustainability leadership for the 18th consecutive year and has been named to the Dow Jones Sustainability North America Index for its carbon reduction efforts, investments in innovative technology and local philanthropy. With respect to land quality, PECO has obtained Conservation Certification from the Wildlife Habitat Council and/or the National Wildlife Federation for eighteen sites (155 acres).

PECO also is focused on being a low-carbon company. From 2015-2023, PECO reduced its greenhouse gas emissions by approximately 50% through infrastructure investments such as the replacement of first-generation sulfur hexafluoride (SF6) filled electrical breakers and replacement of cast iron/bare steel gas piping. PECO's greenhouse gas reduction program is in alignment with the 2018 Pennsylvania Climate Action Plan goal of a 26% reduction in greenhouse gas emissions by 2025. PECO is looking to exceed this goal with our 2030 Path to Clean initiative which aims to reduce Exelon's operational emissions by 50% from 2015 levels by 2030. PECO continues to maintain one of the largest urban green roofs in Pennsylvania (approximately one acre) built on an existing building at its headquarters in Philadelphia that was recently certified by Pollinator Partnership as an important pollinator habitat. Waste recycling also

continues to be a focus at PECO, with recycling increasing from 94% (2016) to 97% (2023), and the Company recently launched an innovative pilot-study using cameras in bulk waste containers to optimize waste pickup and disposal.

In 2023, PECO donated 800 trees to customers via the Arbor Day Foundation's Energy – Saving Trees program and has donated over 10,000 trees in the last 10 years. In 2023, PECO awarded Green Region grants totaling $150,000 to enhance green space throughout the service area in partnership with Natural Lands Trust. The Arbor Day Foundation also recognized PECO for the fifth year with Tree Line USA certification for the Company's Energy-Saving Trees program and its commitment to proper tree pruning, tree planting, and education in its service area. To facilitate this effort and as part of its "ReLeaf" initiative, the Company awarded $200,000 to the PA Horticultural Society ("PHS"), resulting in an additional 7,500 trees planted by PHS-trained "Tree Tender" volunteers across PECO's service territory in 2023. In addition, PECO partners with the Philadelphia Zoo and the Elmwood Park Zoo to donate "browse," which are leafy tree branches removed as part of the Company's vegetation management program, to provide supplemental nutrition and engagement opportunities for the animals. We provided approximately 7,500 pounds of browse with this program in 2023.

Finally, as part of PECO's habitat protection efforts, the Company developed a comprehensive avian protection plan to reduce bird mortalities associated with power line interactions. This plan includes establishing new distribution line construction standards, removing or relocating nests, and providing employee

training on avian management. PECO also recently completed an avian environmental risk assessment of its service territory to identify important bird nesting and roosting areas. Distribution circuits in these areas were evaluated for avian-safe equipment, and the devices were added where needed. Also, as part of proactive measures to protect bald eagles, an inventory of bald eagle nest sites was established, and all distribution circuits within a quarter mile of the active nests were inspected to make sure that avian-safe equipment was present. Retrofits were also made in areas needing avian-safe equipment. Finally, those distribution circuits that experienced repeated avian mortalities were evaluated in a similar fashion, and remedial measures were taken if needed.

33. Q. Please describe the Company's efforts to support the use of alternative fuel vehicles and related technologies.

A. PECO participates in the Edison Electric Institute's challenge to designate at least 5% of its Electric Operations' annual vehicle spending for plug-in technology. Exelon also recently announced that its six utilities, including PECO, will electrify 30% of their vehicle fleet by 2025 and increase fleet electrification to 50% by 2030.

PECO operates its own fleet of 1,452 hybrid, electric, flex fuel, and biodiesel vehicles including 56 plug-in hybrid trucks, nine battery electric vehicles, and 108 Job Energy Management system worksite electrification plug-in aerial trucks. These vehicle numbers will continue to grow in furtherance of PECO's goal to electrify 50% of its fleet by 2030. Between 2020 and 2023, the Company's electrified fleet has saved approximately 91,603 gallons of fuel. The Company

also encourages sustainable practices with employees by providing over 100 EV charging stations, rebate programs, and bike racks at most Company locations.

PECO currently offers residential customers an EV registration rebate. The Company also offers rebates to qualifying non-residential customers for installing Level 2 EV chargers and DC fast chargers (the "EV Charging Pilot") as well as a special pilot rider (the "EV-FC Pilot Rider") for the installation of direct current fast chargers to support the build out of EV infrastructure in Pennsylvania. As explained by Mr. DeMott in PECO Statement No. 10, the Company is proposing to extend the EV Charging Pilot and extend and modify the EV-FC Pilot Rider.

VIII. FULFILLMENT OF 2021 RATE CASE COMMITMENTS

34. Q. In the Joint Petition for Settlement of Rate Investigation that the Commission approved in PECO's last electric base rate proceeding at Docket No. R-2021-3024601 ("2021 Settlement"), the Company made a number of commitments. Has PECO fulfilled or taken steps to satisfy those commitments?

A. Yes, it has.

35. Q. In the 2021 Settlement, PECO also agreed to report on various expenditures. Please describe each reporting requirement and PECO's compliance with this commitment.

A. First, PECO agreed to provide the Commission's Bureau of Technical Utility Services, the Commission's Bureau of Investigation and Enforcement ("I&E"), the Office of Consumer Advocate, and the Office of Small Business Advocate

with an update on its electric division's actual capital expenditures, plant additions, and plant retirements by month for the twelve months ending December 31, 2021. Second, the Company agreed to provide a similar update on or before April 1, 2023, to include actual capital expenditures, plant additions, and plant retirements by month for the 12 months ending December 31, 2022. Finally, PECO agreed, in its next base rate proceeding, to prepare a comparison of its actual expenses and rate base additions for the 12 months ended December 31, 2022, to its projections in the 2021 electric base rate proceeding. PECO met each of these reporting commitments. PECO witness Humphrey describes the Company's 2022 actual expenditures further in her testimony.

36. Q. The Company also agreed to hold a non-wires solutions working group meeting with stakeholders. Did PECO fulfill that commitment?

A. Yes. PECO held the non-wires solution collaborative on February 20, 2022, with various stakeholders, including industry research organizations, renewable developers, environmental and advocacy groups, public officials, and utilities. The feedback received through a combination of presentations and dialogue is being used in conjunction with internal research and industry-wide benchmarking to develop a non-wires solutions framework at PECO.

37. Q. PECO also agreed to convene a collaborative with I&E to discuss safety issues relating to underground residential development cable and PECO's inspections of rear property circuits. Has PECO satisfied these commitments?

A. With respect to inspection of underground residential cable and rear property circuit patrols, PECO met with Commission staff and officially incorporated a five year inspection cycle for fused rear property circuits into its 2024-2025 Inspection and Maintenance Plan (filed September 30, 2022). PECO had already been performing rear property circuit patrols and will complete its fourth year of such inspections in 2024.

38. Q. Please summarize PECO's compliance with other commitments in the Settlement Agreement directly affecting rates, customer programs, and assistance to low-income customers.

A. ***Universal Service Programs (Settlement Paragraph Nos. 28 through 39)***. With respect to PECO's Low-Income Usage Reduction Program ("LIURP"), PECO has accomplished all settlement commitments, including increasing the annual budget, continuing the Company's De Facto pilot (which assists customers in reducing their use of electric portable space heaters), and convening a collaborative to examine usage thresholds for single-family and individual multifamily residential properties. With respect to PECO's MEAF, the Company updated the eligibility criteria and annual contribution amounts per the terms of PECO's most recent electric and gas rate cases, respectively. In addition, PECO has fulfilled its commitments related to expanding CAP outreach efforts.

Customer Service Issues (Settlement Paragraph Nos. 40 to 44). The Company adopted the changes outlined for protection from abuse ("PFA") accounts in Paragraph Nos. 40 through 42 of the Settlement Agreement. PECO implemented additional training for its customer service representatives to help identify

domestic violence victims and process PFAs and similar court orders with clear evidence of domestic violence and updated its related customer materials. In addition, PECO fulfilled all commitments related to language access, including conducting a formal needs assessment using census data to guide outreach efforts to communities with limited English proficiency ("LEP") and establishing a working group that meets twice annually to discuss opportunities to support LEP customers.

EV Programs (Settlement Paragraph Nos. 45-54). As described by Mr. DeMott, the Company has been implementing a multi-component EV Charging Pilot in accordance with its Settlement commitments and a recent Commission Order approving modifications to the Pilot.[2] The Pilot modifications included replacing the original Transit Charging Program with the Public Benefit Charging Program. The Company has also convened a collaborative working group to discuss transportation electrification issues and has been posting Pilot-related data in accordance with its Settlement obligations.

IX. ECONOMIC DEVELOPMENT, COMMUNITY SUPPORT, AND DIVERSITY

39. Q. Please describe PECO's efforts to support economic development and the communities in which the Company provides service.

A. PECO has a dedicated Economic Development Team that works cooperatively with local, regional, and state economic development officials as well as commercial and industrial real-estate professionals to assist businesses that are

[2] *See* Docket No. P-2023-3040238 (Order entered Sept. 21, 2023).

considering locating or expanding in southeastern Pennsylvania. For example, the team provides information on electric and gas availability and prices to companies, developers, and consultants as key inputs to location decisions. The team also works with developers on electric and gas infrastructure strategies for large development sites.

Moreover, as I discussed earlier, PECO makes significant capital and infrastructure investments in its service territory every year that create and maintain thousands of jobs in the region. In early 2020, PECO created a team dedicated to workforce development to attract talented candidates and support our region by providing opportunities to individuals from underserved communities. Since 2020, PECO, in partnership with community partners, has supported the placement of nearly 200 individuals in jobs throughout the region. The Company also implemented a variety of workforce development programs to train individuals for opportunities at PECO, including our Helper Pre-Apprenticeship Program (developed in partnership with IBEW Local 614); a Smart Energy Technical Training Program, an initiative designed to equip unemployed and underemployed individuals from Philadelphia's underserved communities with the skills needed for careers in the energy sector; and annual Infrastructure Academies, where attendees are introduced to various departments.

40. Q. Please discuss PECO's commitment to diversity, equity, and inclusion.

A. PECO has a strong commitment to diversity, equity, and inclusion both among its workforce and in the communities it serves. PECO supports diverse suppliers who represent the diverse customer communities we serve, and we contract with

minority-owned, women-owned and other diverse businesses, contractors, and vendors in our communities and maintain business relationships with local banks. In 2023, PECO expenditures with diversity-certified suppliers totaled $597 million, an increase of approximately $48 million over the previous year. PECO's supply personnel are also active members of numerous supplier diversity-focused organizations locally and nationally.

In 2017, Exelon became the first utility/energy services company to join the exclusive group of U.S.-based corporations that have achieved $1 billion or more in annual, direct spending with minority and women owned businesses. Exelon's annual spending with diversity certified suppliers totals more than three billion. Other Billion Dollar Roundtable member companies include Comcast, IBM, Walmart, and Microsoft.

Exelon has also been named to the 2022 Forbes list of "America's Best Large Employers;" Fortune Magazine's "World's Most Admired Companies;" U.S. Veterans Magazine's "Best of the Best;" U.S. Black Engineer & Information Technology magazine as a "Top Supporter of Historically Black Colleges and Universities;" and The Philadelphia Inquirer's "2023 Top Workplaces;" and received the highest honor by the Center for Energy Workforce Development for excellence in establishing diversity, equity, and inclusion in workforce development to attract and retain a skilled diverse workforce.

41. Q. Are there other ways in which PECO and its employees support their communities?

A. Yes. PECO also has a strong and continuing tradition of community involvement. The Company's corporate citizenship efforts are designed to improve the quality of life for the people who live and work in PECO's service territory and include sponsorships, employee volunteer activities, and executive and employee involvement on outside nonprofit boards. Since 2021, PECO's corporate contributions and employee giving campaigns (including corporate matching gifts) have invested more than $38 million dollars in hundreds of local and regional non-profit programs, organizations, and institutions that provide access to arts and culture, and support STEM education, the environment and green spaces, community vitality, workforce development, and reduction of gun violence. PECO employees have also volunteered nearly 60,000 hours with a wide variety of community organizations. And PECO, along with other Exelon operating companies and the Exelon Foundation, created a $36 million Community Equity Capital Fund, to begin establishing access to capital for small businesses from under-resourced communities so that they can create more jobs, grow their companies, and reinvest in their neighborhoods and communities. Notably, in 2023, PECO was named a recipient of The Civic 50 Greater Philadelphia Award by Philadelphia Foundation, in partnership with Points of Light, for superior corporate citizenship in utilizing the Company's time, skills, and resources to drive social impact within the Company and the communities PECO serves.

X. MANAGEMENT PERFORMANCE

42. Q. Ms. LeVine, based on the performance and achievements you have discussed in your testimony, how do you characterize PECO's record regarding the performance factor considerations of efficiency, effectiveness, and adequacy of service identified in Section 523 of the Public Utility Code?

A. My assessment is based on PECO's demonstrated excellence regarding the quality and reliability of its service, our continuing substantial investment and careful management of expenses, our commitment to energy efficiency, our use of cost-effective new technologies, our vigilance in protecting the safety of its workers, and our strong promotion of community and economic development, all of which I have discussed above. My assessment is also based on PECO's significant and successful efforts to manage and control its operating expenses since its last base rate case in 2021, as discussed by Ms. Humphrey. Based on all of those factors, PECO has exhibited, and continues to exhibit, superior management performance, which fully supports Mr. Moul's recommendation that PECO receive a return on equity enhancement.

XI. CONCLUSION

43. Q. Does that complete your direct testimony at this time?

A. Yes, it does.

PECO ENERGY COMPANY
STATEMENT NO. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

REBUTTAL TESTIMONY

WITNESS: NICOLE LEVINE

SUBJECT: PECO'S OPERATING EXPENSES AND WORKFORCE; MANAGEMENT PERFORMANCE; PECO'S RATE INCREASE AND ASSISTANCE WITH CLEAN ENERGY AND SUSTAINABILITY PROGRAMS

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
NICOLE LEVINE

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Nicole LeVine. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Vice President and Chief Operating Officer. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct testimony marked as PECO Statement No. 1. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will address the following areas:

PECO's Operating Expenses and Workforce. I will respond to the direct testimony of John Defever on behalf of the Office of Consumer Advocate ("OCA") and Bureau of Investigation & Enforcement ("I&E") witness Christine Wilson concerning the appropriateness of proposed rate adjustments for various operating expenses, including vegetation management, organizational memberships, and certain employee costs. I will also address the direct testimony of Lawrence Anastasi on behalf of Local 614 of the International Brotherhood of Electrical Workers, AFL-CIO ("IBEW") concerning his recommendations relating to PECO's workforce.

Management Performance. I will respond to the direct testimony of OCA witnesses David J. Garrett, Nicholas A. DeMarco, and Roger D. Colton, I&E witness D.C. Patel, and Walmart, Inc. ("Walmart") witness Lisa Perry concerning the appropriateness of granting PECO a rate of return on equity near the upper end of Mr. Moul's recommended range to reflect PECO's superior management effectiveness.

Assistance with Clean Energy and Sustainability Programs and Rate Increase. I will respond to the direct testimony of the City of Philadelphia (the "City") and Philadelphia Energy Authority ("PEA") witnesses Emily A. Schapira and Elizabeth H. Lankenau concerning the Company's policies and efforts to support the City and others transitioning to clean energy and achieving their climate and sustainability goals and to the City, PEA and SEPTA witness James L. Crist regarding PECO's rate increase.

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

A. Yes, I have prepared PECO Exhibit NL-1 Response to Interrogatory PECO-CITY/PEA-III-12 and PECO Exhibit NL-2 Response to Interrogatory PECO-CITY/PEA-III-10.

II. PECO'S OPERATING EXPENSES AND WORKFORCE

5. Q. OCA witness Defever proposes to reduce the Company's vegetation management expense by $7.987 million, asserting that the Company has consistently underspent its vegetation management budget and a five-year average of actual vegetation management expense should instead be used. I&E witness Wilson proposes a similar reduction, contending that

PECO's proposed $56 million for vegetation management is higher than the Company's cost in any of the last five years and actual expenses were below budgeted expenses in three of those five years. How do you respond?

A. The Vegetation Management budget includes all programs related to vegetation-related maintenance of our distribution system, not simply the preventive maintenance PECO performs that is measured in miles. These additional programs include removal of hazardous trees and "strategic" trees likely to cause customer outages, trees infected by the Emerald Ash Borer insect, storm and emergency response, corrective maintenance, and grounds maintenance. As documented in discovery PECO produced in this proceeding (see I&E Exhibit No. 1, Schedule 7), PECO prepares separate budgets for each Vegetation Management program area for a combined $56,360,961 FPFTY Vegetation Management program budget.

The storm and emergency response portion of the Vegetation Management budget is used to address costs incurred for storms that do not qualify as major or minor storms (including preparation for storms). During recent years, these storm and emergency response costs have exceeded budgeted amounts by approximately $3,000,000, requiring a reallocation of funds from other parts of the Vegetation Management budget to ensure proper storm response. Table 1 shows the storm and emergency response budget and costs for the years 2018 through 2023.

Table 1: Storm and Emergency Response Budget and Cost

	2018	2019	2020	2021	2022	2023
Budget	$1,192,344.00	$1,192,344.00	$1,160,683.00	$1,157,370.00	$1,127,403.00	$1,153,854.00
Costs	$2,661,647.00	$3,552,473.00	$3,796,214.09	$3,837,201.61	$4,138,641.09	$5,725,479.12
Difference	**-$1,469,303.00**	**-$2,360,129.00**	**-$2,635,531.09**	**-$2,679,831.61**	**-$3,011,238.09**	**-$4,571,625.12**

In addition to higher storm and emergency response costs, PECO has also increased its proactive efforts to address hazardous and strategic tree removals to reduce vegetation-related customer outages. Due to the abundance of ash trees with Emerald Ash Borer in PECO's territory, their large size, dangerous brittle conditions, and specialized equipment requirements (such as cranes) for worker safety, the removal expenses per tree continue to increase.

Given the breadth of programs under Vegetation Management and the need to reallocate some of these funds for the reasons I have discussed, the difference in the budgeted miles trimmed and the number of actual miles trimmed since 2019 (which was only 8%) is not an appropriate basis to reject the Company's proposed increase of $6.1 million, as I&E and OCA both propose. The proposed increase of $6.1 million includes an additional $3,000,000 to cover the recurring increase in emergency and storm response costs documented above, as well as $2,000,000 for a strategic reliability improvement initiative to address vegetation-related customer outages and additional adjustments for increased costs of unionized contract labor (which tends to increase faster than inflation) and fuel costs. The strategic reliability improvement initiative is a new program to use additional vegetation trimming and more expansive tree canopy removal to reduce the number of customers experiencing repeat outages during consecutive years. As

described in I&E Exhibit No. 1, Schedule 7, the initiative will be performed in addition to PECO's regular vegetation maintenance and will remove dead or declining trees along the conductor path as well as non-compatible fast-growing trees that are below or beside the distribution system line. In light of the storm costs I have documented and the additional vegetation management programming to reduce repeat outages, the Commission should reject the proposed Vegetation Management adjustments of both OCA and I&E.

6. Q. Mr. Defever proposes a 50% reduction in the amount of funds ($880,790) for industry dues, as he believes PECO's membership and involvement in industry organizations have not demonstrated benefits for customers. Do you agree?

A. No. Validation of skills from a professional institute helps to mitigate risk, especially relating to safety and reliability. PECO's involvement in these organizations fosters a motivated and engaged workforce, provides career advancement for employees, and helps give PECO a competitive advantage over other employers in the area. With the rapid pace of change in the electric industry and ongoing electrification efforts, such as green energy and electric vehicle adoption, it is vital for utilities to participate in education and collaboration opportunities. These opportunities may be technical as well as non-technical in nature, fostering open communications with industry partners, economic development entities, and the communities we serve to ensure continued service reliability.

Industry partnership programs created from these memberships support PECO's commitment to clean energy and increase service reliability. For example, PECO's membership in the Edison Electric Institute supports PECO's efforts in integrating renewable energy, including PECO's Path to Clean initiative with emission reduction goals of 50% by 2030 and reaching net zero by 2050. PECO's membership in the Electric Power Research Institute supports our work on fleet electrification planning and assessments to address future capacity needs. Membership in the Energy Association of Pennsylvania provides a variety of best practice information sharing across Pennsylvania electric distribution companies ("EDCs"), including information relating to FERC Order 2222 interconnection aggregation requests. Membership in the Southeastern Electric Exchange provides storm restoration resource coordination with member utilities to minimize customer outage duration.

7. Q. Do you agree with Mr. Defever's proposal to reduce the Company's proposed allowance for dues to non-industry organizations by $136,455?

A. No. While I agree that Commission precedent does not permit charitable contributions to be recovered from customers, I disagree that non-industry membership dues paid to such organizations as the Pennsylvania Economy League are comparable to charitable contributions. As Mr. Defever acknowledges, Commission precedent has supported membership in chambers of commerce, and PECO explained in discovery that membership in these additional organizations promotes the interests of PECO's commercial and industrial customers, and the residents of PECO's service territory overall by engaging with

the business community and promoting partnerships to grow the local economy. I do not believe there are simply "the possibility of benefits," as Mr. Defever suggests. For example, PECO partners with Select Greater Philadelphia ("Select"), an organization that focuses on growing the economic vibrancy of our collective community through attracting new businesses and new jobs to the region. PECO works closely with Select to address the energy requirements of companies interested in locating or expanding in the Greater Philadelphia area. Expansion of the Company's customer base benefits PECO customers through a lower distribution revenue requirement. Select's mission to attract new business and jobs also creates new job opportunities for PECO customers.

As Mr. Defever mentions, PECO is a member of the organization Wildlife Habitat Council ("WHC"), which provides certification of PECO's stewardship properties via a third party verified process. WHC sites are used to provide habitat for wildlife and to assist with community outreach activities associated with biodiversity enhancement and conservation education. PECO manages many of its transmission and distribution Right-of-Ways using integrated vegetation management methods which promote the use of native plants to provide habitat for pollinator species, and some of these sites are WHC certified. WHC certification financially benefits ratepayers by reducing property maintenance costs; for example, certified sites require a reduction in mowing and the use of native plants directly reduces stormwater runoff, improves water quality and reduces PECO's impacts associated with climate change.

PECO also partners with the Economy League of Greater Philadelphia because we support their more macro efforts to have a positive impact on businesses in the region. This focus aligns with PECO's utility economic development mission to work with partners to attract businesses to the region and while also helping existing businesses grow and expand here. We believe that working to make the region a better place to do business directly impacts companies' decisions to locate to Philadelphia and the surrounding areas. Additionally, other organizations that PECO participates in – including Central Philadelphia Development Corp., Independence Business Alliance, and the Philadelphia Convention and Visitors Bureau – provide valuable resources and programs to attract new businesses and to help businesses expand their operations or stay within PECO's service territory, thereby generating new jobs or protecting existing jobs, which benefits PECO and its customers directly. As I mentioned earlier, expanding the Company's customer base also provides direct benefits to existing customers through a lower distribution revenue requirement.

8. Q. Mr. Defever recommends that the Commission disallow the Company's request to recover $115,490 for employee recognition and service awards, claiming that this type of expenditure should be recovered from shareholders not ratepayers. Similarly, Ms. Wilson recommends a reduction of $775,100 in employee activity expenses associated with an annual employee picnic. Do you believe these reductions are appropriate?

A. No, I do not. PECO's claim for employee recognition and service awards and the cost of our annual picnic gathering for our employees have real benefits in terms

of employee morale and productivity. Counsel has informed me that the Commission has recognized the importance of employee recognition costs and events in contributing to a utility's workplace environment. I believe our celebration of employees and recognition of employee service is an appropriate expense that help make PECO an attractive workplace for its many talented professionals. Employee engagement-related activities and associated costs are a means to increase employee engagement and celebrate our workforce, their accomplishments, and strategic goals and initiatives. Employee engagement is a combination of the extent to which employees take pride in the company, are willing to exercise discretionary effort to improve the operations of the business and the customer experience, and the ability of the Company to attract and retain the talent we need to perform at an exceptional level. This directly benefits the Company's customers, as hiring and retaining top-level talent is imperative to continuing to provide PECO's customers with excellent service.

9. Q. Mr. Defever similarly recommends that the Commission disallow the Company's request to recover $121,810 related to the employee cafeteria claiming that the costs are not related to, or necessary for, the safe or reliable provision of service, and ratepayers receive no benefit. Do you agree with this reduction?

A. No. PECO has an employee cafeteria to support over 1,300 employees who are assigned to the Main Office Building on a daily basis. In addition to salaried personnel, PECO also employs people at the Main Office Building in hourly positions such as Care Center Representatives, Clerical Support, and Control

Room Operators. People in hourly positions have limited time away from their work locations for meals due to the continuous need for their role to be attended. By offering an on-site cafeteria, employees are afforded the ability to purchase and eat their meals within their allotted meal times. PECO's employee cafeteria also provides food catering services to employees when working around the clock (24/7) in the Emergency Operations Center, and prepares boxed lunches for crews who are going off-system for mutual assistance support. The small cost budgeted to ensure that our employees have quick and reliable access to meals in times of emergency support, as well as a convenient and quick option for breakfast and/or lunch when working in the Main Office Building, is a very cost-effective means to provide a quality benefit to all employees that ensures a timely return to work responsibilities, increases employee satisfaction, and potentially supports employee retention.

10. Q. Mr. Defever proposes to reduce the Company's employee expense by $326,470, arguing that this amount is an appropriate reduction to address time during the workday spent by some employees in volunteer activities which, in his view, are comparable to charitable donations that should not be funded by ratepayers. Do you agree?

A. Volunteer events are an opportunity for PECO employees to directly interact with and serve customers in the community.

Volunteers are often supporting PECO-led initiatives (e.g., summer fan distribution or tree giveaways) that benefit the entire community or general community projects. Volunteers also assist with projects that benefit the region's

environment, including performing trail restoration and clean-up following major weather events. In addition to the obvious customer benefits of such direct assistance, affording employees the opportunity to help the communities PECO serves is a primary form of employee engagement and is beneficial to recruiting and maintaining employees.

11. Q. Mr. Anastasi recommends that PECO be required to file an annual workforce planning report that identifies "challenges" PECO faces, with specific requirements for providing the number and age of employees in various job classifications, the anticipated hiring and attrition levels for those positions, and the specific actions PECO is taking to address these "challenges." Do you agree with this proposal?

A. As a threshold matter, I do not agree with his premise that PECO faces any "challenges" in its workforce planning, and his "concerns" regarding possible "deficits" in highly skilled workers are entirely general. As Ms. Humphrey discusses in more detail, we conduct multiple Electric Operations Schools each year to ensure that we are able to meet our actual hiring needs. And while I appreciate the interest of IBEW in exploring PECO's hiring plans through a required "workforce planning report," our detailed hiring plans are - and should remain - within the managerial discretion of PECO. Mr. Anastasi offers no criticism of the current collaborative processes between PECO and IBEW, and I believe that collaboration is more than sufficient to address any legitimate concerns of the IBEW.

12. Q. Mr. Anastasi also recommends certain criteria by which PECO should assess project bids for contracted projects for the purpose of ensuring that a qualified workforce is performing the work, including requirements relating compliance with prevailing wage requirements, insurance, safety training, and participation in apprenticeship and training programs approved by the United States Department of Labor. How do you respond?

A. Mr. Anastasi's proposal is not necessary as PECO already uses a robust strategic sourcing process for requests for proposals, and all responding entities go through a rigorous qualification process. All of our contracts also include extensive terms and conditions that impose requirements in virtually all of the areas identified by Mr. Anastasi, including explicit provisions requiring contractors to provide qualified employees and to document those qualifications when required. These same procedures and contractual provisions will also apply in PECO contracts relating to electric vehicle infrastructure highlighted by Mr. Anastasi.

In light of Mr. Anastasi's, concerns, I note that the vast majority of PECO's "contractors of choice" use union labor, including all PECO contractors of choice working on distribution overhead lines. The unions have their own processes to certify qualified employees as well. While we do not have specific requirements that our contractors use apprenticeship and training programs approved by the U.S. Department of Labor or provide additional information on "qualitative" factors "affecting the long-term viability of Pennsylvania communities" or other asserted "best value" employment metrics, I do not believe such requirements are

necessary or appropriate to ensure that our contractors are performing required work on PECO's distribution system at a competitive price for customers.

In addition to the items above, Mr. Anastasi also proposes that PECO adopt a training program requirement (the Electric Vehicle Infrastructure Training Program) which, as reflected in Mr. Anastasi's testimony, is focused on electric vehicle charging stations. At the current time, PECO does not install EV charging infrastructure that will be used by customers. Any customer-facing EV charging infrastructure in PECO's service territory is currently installed and maintained by the customer, and not by employees, contractors, or subcontractors of PECO. As such, there is no need for PECO to adopt this training program and the Commission should reject Mr. Anastasi's proposal.

III. MANAGEMENT PERFORMANCE

13. Q. In your Statement, you support Mr. Moul's recommendation that PECO receive an enhanced return on equity. Why?

A. As explained in my direct testimony, PECO has demonstrated excellence with regard to the quality and reliability of its service, its commitment to energy efficiency, its willingness to embrace cost-effective new technologies, its vigilance in protecting the safety of its workers, and its strong promotion of community and economic development. As Ms. Humphrey explained in PECO Statement No. 2, PECO has also successfully managed and controlled its operating expenses since its last base rate case in 2021 to deliver savings to customers. Notably, PECO's projected annual O&M growth rate since 2022 is 25% lower than the recent average 5.5% inflation increase in the Consumer Price

Index. The Company's projected O&M growth rate is 4.1% when adjusted for storms and "make-ready" work requested by third parties. My direct testimony highlighted a variety of other accomplishments, including our System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") performance. In addition, PECO had significant reduction of customer interruptions, new distribution system automation investments that avoided over 2.2 million interruptions between 2021 and 2023, and a large number of customer service enhancements that have led to our ranking as 2nd out of 17 electric utilities in the J.D. Power Residential Customer Satisfaction Study for the East Large region.

14. Q. Did any parties oppose the Company's proposal to apply an exemplary management performance increase to the return on equity?

A. Yes. Mr. Patel, on behalf of I&E, contends that the Company's performance does not exceed the level of performance that is required by Pennsylvania public utilities. Mr. Patel claims that if a Company is successful at controlling operating and maintenance costs, then those cost savings would be offset by an increase in rates through an adjustment of return to reflect exemplary performance, thus defeating the purpose of cost-cutting measures to benefit ratepayers. He also believes that any performance factor recognition should be awarded on a case-by-case basis and that existing precedent is distinguishable here.

Three witnesses from the OCA lodged similar objections. First, Mr. Garrett raised concerns similar to those raised by Mr. Patel that management performance generally does not have a material effect on the cost of equity and utilities should

not be rewarded for operating systems in a prudent manner, as required by law. He also raises a more specific concern that some of the claimed excellence of performance is related to actions taken by the diversified PECO Energy rather than PECO Electric. Second, Mr. Colton testifies that the Company does not do enough with respect to the administration of its universal service programs, including program enrollment and communication with low-income customers, to warrant a management performance adder. He also disputes statements that the Company has invested in technology that supports assistance programs and affordability. Third, Mr. DeMarco's testimony argues that the Company is not entitled to a management performance adder because it has not provided more than the adequate and reasonable customer service it is obligated to provide as a public utility. In addition, Ms. Perry, on behalf of Walmart, objected to an award of management performance, contending that the Company has not provided evidence sufficient to support a clear and specific measure that excellence has been achieved.

15. Q. Do you agree with these objections?

A. No. Pursuant to 66 Pa C.S.A. §523, the Commission has the authority to consider a utility's performance to grant additional basis points to the return on equity. As noted above, the evidence in this proceeding supports such an adjustment. There is no question that PECO is required to deliver utility services efficiently and effectively to benefit our customers, and we have certainly done that. But what I have described goes well beyond "business as usual" as shown by our reliability and safety metrics, our continuing customer service improvements, and the other

innovations I discuss in my direct testimony. Mr. Moul addresses the objection relating to recognition of management performance for both PECO's electric and gas operations. With respect to Mr. Colton's specific objections, Ms. Golden explains in her rebuttal testimony that PECO's low-income assistance programs have expanded significantly. After the Company redesigned its Customer Assistance Program ("CAP") to function as a percentage-of-income program ("PIP") and the Commission reduced the calculated "energy burden," PECO's CAP customer credit program expanded from $86 million in assistance to more than $140.7 million. And as Ms. Golden describes, we conduct hundreds of events in our service territory each year to help ensure that our customers in need have access to the full range of low-income assistance programs that are available. The Assistance Finder tool on PECO's website also uses technology to help customers find programs designed to support their specific needs all in one place (e.g., financial assistance, bill management, saving energy). In short, PECO has continued to deliver superior performance worthy of recognition by the Commission.

IV. PECO'S RATE INCREASE AND ASSISTANCE WITH CLEAN ENERGY AND SUSTAINABILITY PROGRAMS

16. Q. The City and PEA generally assert that higher electric rates will adversely affect City residents and small businesses, raise the cost of electrification, negate energy efficiency investments, and increase the costs of the City's effort to combat climate change. SEPTA witness Crist also contends that an increase in electric rates will adversely affect SEPTA and its ridership. How do you respond?

A. As I discussed in my direct testimony, and as Ms. Humphrey also explained, the Company has worked to keep expenses low even at the same time as we modernize our distribution system infrastructure and make infrastructure investments to serve new customers and customers whose electric energy needs are growing. As the City moves forward with its electrification and other clean energy efforts, PECO's investments in its distribution system infrastructure are more important than ever to ensure reliability and resiliency for our customers. We have also taken action to obtain additional resources, including being one of the few utilities nationwide selected to negotiate for up to $100 million in federal funding under the Infrastructure Investment and Jobs Act to further modernize our electric grid operations. Developing this grant application required a comprehensive organizational effort, but our customers will be the beneficiaries, as the funding received through this grant will reduce their costs on a dollar-for-dollar basis. Furthermore, we have developed extensive programs to ensure that our utility service remains affordable for our low-income customers, which PECO witness Jackie Golden has addressed in detail.

With respect to energy efficiency investments, Mr. McGraw suggests that PECO's costs should be declining as the City and other customers install equipment supported by PECO's Act 129 program (including the City's new streetlights) and this rate increase could reduce customer savings from those investments. However, as the General Assembly recognized in enacting Act 129 and permitting electric distribution companies to recover lost revenue arising from Act 129 programs, more energy efficiency investment can reduce the revenue of

an electric distribution utility without reducing the costs necessary to continue to provide service and invest in necessary electric system infrastructure, including equipment that will facilitate increased energy efficiency.

17. Q. In testimony submitted on behalf of the City of Philadelphia ("City") and the Philadelphia Energy Authority ("PEA"), City/PEA witnesses contend that PECO is not sufficiently supporting the City's goals relating to electrification and climate change. Do you agree with their criticisms?

A. Absolutely not. As I explained in my direct testimony, we are engaged in a wide variety of programs to help our customers achieve their goals relating to renewable energy. We have streamlined our processes for interconnection of solar facilities, developed an interactive viability map to facilitate solar applications and solar interconnections, and automated the technical analysis for the majority of Level 1 and smaller Level 2 solar applications. More broadly, we are engaged in an extensive program to convert distribution facilities to operate at higher voltages to facilitate more interconnection of customer-owned distributed generation. And as described by Company witness Steven J. DeMott, the Company is developing a range of programs to assist customers with electric vehicle charging infrastructure.

With respect to interconnection of solar energy systems, our "Green Power Connect" ("GPC") team has reduced the time period for interconnection by 72 days since 2018. And a portal on our website provides solar developers transparency and insight into the interconnection process by allowing them to

check the status of a project and communicate directly with PECO regarding that project.

PECO's GPC team continues to look for ways to automate processes to further reduce interconnection timelines. Specifically, the GPC team has automated the underwriters' process and the Permission to Operate ("PTO") process. During COVID-19 it became more difficult to process interconnection application fees, and GPC is currently working to develop an online payment system to ultimately automate this process.

More broadly, we have worked closely with a variety of governments and organizations in the region – including the City – in supporting sustainability programs and commitments, including efforts to obtain additional funds. For example, PECO has provided letters of support and collaboration for the following federal grant applications over the last three years:

- Delaware Valley Regional Planning Commission ("DVRPC") "Clean Energy to Communities"
- School District of Philadelphia and Unionville-Chadds Ford "Clean School Bus"
- City of Philadelphia "EV Workforce Development"
- City of Philadelphia "Clean Fueling Infrastructure"
- DVRPC "Clean Fueling Infrastructure"
- Philadelphia International Airport "Airport Terminal Program"
- SEPTA "Low and No-Emission Vehicle Program"
- PhilaPort "Clean Ports Program"

- Pennsylvania Department of Environmental Protection "Transmission Siting and Economic Development Program – Area 2"
- Pennsylvania Public Utility Commission "Transmission Siting and Economic Development Program – Area 1"
- MidAtlantic Clean Hydrogen Hub – MACH2, "Regional Clean Hydrogen Hubs"

Further, PECO has worked extensively with the City of Philadelphia to support its electrification initiatives, including the following activities:

- Bi-monthly meetings with the City Office of Sustainability to discuss issues of mutual interest.
- Supporting, at the City's request, the City's internal EV Working Group from September to December 2023.
- Inviting representatives from the City of Philadelphia to attend meetings of PECO's EV Collaborative and providing an opportunity for the City to present on the work of its EV Working Group in May 2024, including a fleet electrification "Lessons Learned" program to assist other organizations plan and execute their own fleet electrification programs.
- Agreeing to provide content and instruction for the City's successful "Plug-In Philly" Electric Ride-and-Drive workforce development grant and serving as a core team member on City-scheduled implementation meetings.

To date, the City's requests for support of its electrification initiatives have been quite limited. The City did not submit any applications for incentives under PECO's Level 2 commercial incentive program in the first two years of its availability. The Company is pleased that the City has started taking advantage of this opportunity in 2024 and looks forward to continuing to support the City's applications if the proposed extension of the Public Benefits Charging program

discussed in Mr. DeMott's testimony is approved. We also welcome the opportunity to engage the City in broader discussions regarding its vehicle electrification strategy and encourage the City to share with us information on its electrification plans. While we will always require the filing of a service and meter application for individual customer site upgrades, we do believe there is significant opportunity to collaborate with the City on its strategic approach to electrification. I note, however, that any suggestion that PECO has delayed the City's rapid deployment of electric vehicle charging stations is misplaced; as shown in PECO Exhibit NL-1, the City stated that its current plans for 2025 include only three fast chargers and they "hope to install" just ten Level 2 chargers in 2025.

With respect to the City's request regarding increased cost sharing of interconnection costs, the City correctly states that when distribution capacity increases are needed in order to enable new solar interconnection, the customer seeking the new interconnection may be required to pay those costs. However, the customer is only responsible for the portion of the capacity increase that they are expected to need. Once in service, any capital cost of the infrastructure upgrade that is not covered by the customer is included in the Company's rate base. PECO believes that this approach to cost sharing for infrastructure upgrades provides for equitable financial responsibility. In the case of the Northeast Philadelphia Airport project discussed by the City/PEA, the airport is the sole customer and only beneficiary of the infrastructure upgrades sought by the City.

18. Q. The City and PEA argue that PECO has not taken sufficient action to procure more renewable energy, and that PECO's rate increase should be conditioned on PECO providing more assistance in assisting the transition of the region to a low carbon economy. Do you agree with the City and PEA?

A. No, not at all. PECO does not own any generation, but in its role as default service supplier, we procure energy for those customers who do not select an electric generation supplier ("EGS") or who return to default service after being served by an EGS that becomes unable or unwilling to serve. We have a statutory obligation to procure these resources at least cost to our customers over time. In this role, at least 18% of the generation delivered to our customers already comes from alternative energy sources, as measured by alternative energy credits, with 8% from so-called "Tier I" resources (such as wind and solar energy projects) and the remainder from "Tier II" resources (such as hydropower). We have also initiated programs to procure solar alternative energy credits from solar facilities in Pennsylvania and in our service territory, including the City. These energy procurement issues are not relevant to this proceeding, but are fully addressed in our regular default service proceedings. However, I note that in PECO's most recent default service proceeding, now pending before the Commission, PECO agreed with other parties to conduct a procurement for up to 25 MW of solar energy, capacity and solar alternative energy credits from solar projects in Pennsylvania that will be used to serve default service residential customers.

Ms. Schapira's assertion that our plans for reductions in PECO's own greenhouse gas emissions are only "a website" is entirely wrong. As I have noted, PECO, as

part of Exelon, has developed a detailed Path to Clean for reduction of its greenhouse gas emissions and that is detailed in our latest sustainability report.[1]

19. Q. The City also asserts that PECO is not considering the possibility of increased demand and interconnections from electrification, in part because you testified that PECO expects overall sales to be "nearly flat," and the City proposes that PECO should be required to consider such increases in establishing its rates. Please respond.

A. There is no need for such a requirement as we do anticipate increased electrification in the future, particularly in the area of transportation electrification, and we are working with a variety of stakeholders to support those efforts. Future electrification will actually involve more infrastructure investment, not less, and the revenue effects can be difficult to project in light of the increased energy efficiency of various technologies. For purposes of this proceeding, however, PECO is required to present rates to serve customers during the fully projected future test year and not rates based on the load that will result from a significantly more decarbonized system in the future. And as I have already described, we are devoting significant resources to expanding our interconnection capabilities in terms of our distribution infrastructure and our interconnection processes and systems.

[1] *See* https://www.exeloncorp.com/sustainability/interactive-sustainability-report?year=2022&page=1.

20. Q. The City and PEA expressed concern over the Solar Power Purchase Agreement in 2022 at Philadelphia's Northeast Airport and the interaction with PECO. Do you believe their concerns are appropriate?

A. No. The solar project referenced by the City and PEA was complex and not typical of other commercial projects. Ultimately, this project was completed, although it encountered delays due to the City and/or its vendors extended response times and documents being filed incorrectly. PECO's records show that the developer created an application on October 7, 2021, and it remained in DRAFT status on PECO's systems until being submitted to the GPC team on Wednesday, February 9, 2022. In the interim, the GPC Contract Liaison sent multiple messages to the developer informing them of the DRAFT status with no responses received. Once the application was submitted, it contained inaccurate information and had to be sent back to the developer multiple times to be corrected. PECO provided conditional approval on Wednesday, April 13, 2022, but deficiencies with the customer equipment rating and safety concerns with the effective grounding of the project were then identified. The Company met with PEA several times throughout the process to discuss issues with the project and to work toward solutions, and the project completed construction on March 4, 2024.

21. Q. City witness McGraw asserted that "many" of the City's electrification and renewable energy projects had been delayed or abandoned due to PECO's processes, and the City and PEA propose new reporting requirements for PECO's interactions with the City and other government organizations on "energy transition projects". How do you respond?

A. As shown in PECO Exhibit NL-2, the City was unable to substantiate its claims that "many" projects were delayed or abandoned. When asked, the City was only able to identify the Northeast Airport solar power purchase agreement and PECO's requirements for electric vehicle service applications, which I have already addressed.

As I mentioned above, PECO actively works with the City on various projects and initiatives. Currently, the PECO GPC team is working with the City on the implementation of six EV charging stations. PECO has evaluated the projects and is waiting on a response from the City in order to progress them. In addition, to foster a collaborative working relationship, PECO's GPC hosts bi-weekly meetings with the City in regards to their solar projects. These meetings enable PECO to work directly with the City to discuss any projects that need special attention and provides an opportunity for both PECO and the City to learn from each other and make continuous improvements. These meetings are also important as they provide an opportunity for PECO and the City to work together on additional programs, including PECO's solar collaborative. Moreover, as I have already described, PECO is successfully working with a variety of governments and organizations throughout the region to support many energy and sustainability projects. The City has failed to show any need for its proposed new reporting requirement, and PECO is concerned that the addition of burdensome new reporting requirements will misallocate resources and hinder, rather than enhance, the Company's ability to support requests from customers related to

energy efficiency and clean energy projects. For these reasons, the Commission should reject its proposal.

22. Q. OCA witness Nelson comments that PECO should prepare an "orchestration plan" for distributed energy resources, a process for distributed energy resource management system functionalities, and a "load management plan" to address import and export on its distribution system. How do you respond?

A. As stated previously, PECO maintains focus on safety and reliability, as well as continuing customer service improvements. This includes modeling the impact of electric vehicle and distributed energy resource ("DER") adoption throughout the service territory and employing forecasting tools to ensure adequate future system capacity. PECO is deploying LoadSEER software, which will provide these advanced forecasting capabilities. This software is targeted for implementation at the end of 2024. PECO is also developing DER data architecture models that will advance or enable multiple other DER-specific capabilities such as monitor and control, enhanced DER interconnection, and DER aggregations authorized by FERC Order 2222. In addition, PECO collaborates with EPRI and other industry organizations to gain a deeper understanding of the advantages, disadvantages and challenges involved in implementing the more advanced capabilities. PECO is part of EPRI's P199 Electrification, P204 Advanced Building and Communities, and P174 DER Integration programs. PECO also partners with external organizations to validate growth forecasts to ensure the continued efficient management of financial resources.

PECO continues to successfully facilitate the distributed energy resource interconnection process within the service territory utilizing existing systems and communication network. As DER penetration increases, future potential communication upgrades would be vetted through a financial benefit-cost analysis prior to approval. In light of the rapid developments in this sector and PECO's on-going work to support DER, PECO does not believe the Commission should impose any additional requirement. Should the Commission believe any new DER-related requirements are appropriate, those requirements should be considered as part of a proceeding applicable to all Pennsylvania EDCs.

V. CONCLUSION

23. Q. Does this complete your rebuttal testimony at this time?

A. Yes, it does.

CITY/PEA RESPONSES
TO PECO SET III

PECO-CITY/PEA-III-12. Reference City and PEA Statement No. 2, page 4, lines 20-22 and lines 5, p. lines 1-2. Please provide the types and number of each type of electric vehicle charger the City intends to install in calendar year 2024 and the amount of City funds budgeted for those chargers in calendar year 2024.

RESPONSE: The City's Department of Fleet Services (DFS) has budgeted $750,000 for DC Fast Charger projects in FY25. DFS aims to install at least three DC Fast chargers in FY25.

The Office of Sustainability (OOS) has budgeted $500,000 for level 2 EV charger projects in FY25. We hope to install at least ten 19.2 kW level 2 chargers in FY25, but this greatly depends on the electrical upgrades needed at municipal facilities.

WITNESS: DOMINIC G. McGRAW

DATED: 7/5/2024

CITY/PEA RESPONSES
TO PECO SET III

PECO-CITY/PEA-III-10. Reference City and PEA Statement No. 2, p. 4, lines 9-12. Please list all projects the City and/or PECO contend are or were "delayed" or which the City and/or PEA abandoned due to "PECO not having the proper infrastructure, planning, and processes in place for electrification and other renewable energy projects to be approved a completed in a timely and cost-effective manner." For each such project, list (i) the specific item (s) or process(es) the City and/or PEA contend that PECO did not have or provide; (ii) all relevant dates on which the City and/or PEA made a request to PECO and the City or PEA believes PECO's response to that request was delayed; (iii) the date(s) on which PECO provided the City and/or PEA with the requested item or result or the City and/or PEA's current understanding of the status of the requested item or process.

RESPONSE: City and PEA Statement No. 2 covered the most significant example of this for the City which was the Airport's solar project, as well as the difficulties that the City has had with PECO's EV processes. The City would need more time to put together a comprehensive list of every example. The City and PEA have objected to Section (iii).

WITNESS: DOMINIC G. McGRAW

DATED: 7/5/2024

PECO ENERGY COMPANY
STATEMENT NO. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

SURREBUTTAL TESTIMONY

WITNESS: NICOLE LEVINE

SUBJECT: PECO'S WORKFORCE;
INTERCONNECTION OF SOLAR
GENERATION

DATED: AUGUST 2, 2024

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SURREBUTTAL TESTIMONY
OF
NICOLE LEVINE

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Nicole LeVine. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Vice President and Chief Operating Officer. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct and rebuttal testimony on behalf of the Company, which are marked as PECO Statement No. 1 and 1-R, respectively. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. My surrebuttal testimony will address the rebuttal testimony of Lawrence Anastasi on behalf of Local 614 of the International Brotherhood of Electrical Workers, AFL-CIO ("IBEW") concerning his recommendations relating to PECO's workforce and the supplemental direct testimony of Nicholas A. DeMarco on behalf of the Office of Consumer Advocate regarding testimony at the public input hearings regarding interconnection of solar generation.

II. PECO'S WORKFORCE

4. Q. Mr. Anastasi states that IBEW would support PECO's vacancy factor of 2% if PECO can show it will change: (1) its hiring practices by offering more competitive wage and benefit packages and expanding its recruitment efforts and (2) its retention policies to curb turnover, implement training opportunities, and encourage internal advancement. How do you respond?

A. First, as Ms. Humphrey explained in her rebuttal testimony (PECO Statement No. 2-R), PECO's vacancy rate of 2% is entirely correct. With respect to Mr. Anastasi's proposal, there is no need to change PECO's hiring practices, as they are clearly effective. PECO offers a highly competitive wage and benefits package for its employees. I note that the Company and IBEW have negotiated several collective bargaining agreements, each time reaching a mutual agreement on wages and benefits through good faith discussions.

In terms of recruitment, PECO has expanded our outreach for craft positions through our workforce development programs. PECO is actively working to fill internal apprenticeship programs for electric classifications through a number of initiatives, including the following:

- Conducting Infrastructure Academies
- Implementing the Helper Pre-Apprenticeship Program
- Hosting the Junior Infrastructure Academy
- Collaborating with community-based workforce development organizations like OIC Philadelphia, CAAP, Orleans Tech, and Williamson College of the Trades.

Mr. Anastasi recommends that PECO adopt "Lead" positions so that experienced employees can phase out of physically-demanding operations and show the

younger workforce that PECO offers internal opportunities for career advancement. In response, I note that PECO's Helper Pre-Apprenticeship Program has been successful in providing "feeder" roles into other bargaining unit positions. Internal advancement to positions such as Foreman, Master Tech, and Supervisor, as well as office positions such as Project Construction Manager, Designer, Design Construction Consultant, Operator and Dispatcher roles are also available to many craft position employees. Field experience provides an excellent background for these roles. Additionally, PECO has maintained a low turnover rate which is proof of strong retention and also indicative of a reasonable overall total benefits package provided to IBEW employees.

PECO strongly believes in the importance of having craft employees involved in PECO training programs. In line with Mr. Anastasi's recommendation, PECO currently offers training focused on career development, technical improvement, and advancements in new technology. To that end, the Company and IBEW recently negotiated and reached agreement establishing a pilot program for a training "Subject Matter Expert" position. This position partners with the training organization to help review and develop PECO's curriculum for training our craft positions. PECO hosts Training Council meetings, that bargaining unit leadership participate in, where training offerings are reviewed and discussed. This collaborative process ensures PECO employees are well-trained and prepared for the latest technology. In addition, PECO currently partners with IBEW for the Company's various craft training schools. Through this partnership, IBEW provides members to work as cadre during the school, which provides an

opportunity for experienced workers to share their experiences with newly-hired candidates. Furthermore, the training of IBEW members who are PECO employees is subject to, and is fully outlined in, the collective bargaining agreement agreed to by IBEW and the Company. Any proposals to change certain provisions governed by that collective bargaining agreement should be handled between the parties in the context of future negotiations of that agreement.

5. Q. In relation to PECO's request to recover operating expenses for the Company's Vegetation Management Program, Mr. Anastasi states that the IBEW encourages PECO to use internal labor for its vegetation management teams. How do you respond?

A. The use of PECO's internal labor is not appropriate for vegetation management. As a utility, PECO's core function is to provide safe and reliable power to its customers. PECO is not a utility line clearance, tree care, or arborist company. In fact, utility arboriculture is an established industry that provides a specialized and complex product with inherent danger. PECO's current utility line clearance contractor provides over 100 crews and 400 full-time equivalent ("FTEs") to support PECO with reliable, cost-competitive vegetation management. The utility line clearance contractor model also enables PECO to quickly and efficiently add additional resources in the wake of large storms or other significant weather events. Implementing a large-scale utility line clearance operation within PECO would be inefficient, burdensome, and counter to industry practice.

Mr. Anastasi's additional contention that PECO provides little oversight of the vegetation management work is simply not true. PECO currently employs certified arborists and utility arborists who oversee the utility line clearance contractor and assess the scope, quality and safety of the work being performed. In addition, PECO utilizes a third-party vendor to provide another layer of independent quality control of this work. For these reasons, utilizing PECO's internal labor workforce to perform vegetation management work would not increase cost-effectiveness or reliability as Mr. Anastasi contends.

III. INTERCONNECTION OF SOLAR GENERATION

6. Q. Mr. Demarco refers to several customers testifying regarding "solar customer service" and recommends that PECO respond to the concerns of these customers. Do you have a response?

A. Yes. I note that none of these customers appear to be testifying about a specific experience with PECO regarding the interconnection of a customer-owned solar system but instead discuss how improving and expediting PECO's interconnection process would facilitate a more rapid transition to clean energy. As I testified in my direct and rebuttal testimony, PECO has devoted substantial resources to enhancing and streamlining the customer solar interconnection process and we will continue to do so.

IV. CONCLUSION

7. Q. Does this complete your surrebuttal testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046931**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Nicole L. LeVine, hereby state that I am the Senior Vice President and Chief Operating Officer of PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 1
- PECO Statement No. 1-R
- PECO Exhibit NL-1
- PECO Exhibit NL-2
- PECO Statement No. 1-SR

Dated: August 5, 2024

Nicole L. LeVine

PECO Statement No. 2:

Direct Testimony of Marissa Humphrey

PECO ENERGY COMPANY
STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

DIRECT TESTIMONY

WITNESS: MARISSA HUMPHREY

SUBJECT: PECO'S NEED FOR RATE RELIEF; EFFORTS TO CONTROL CUSTOMER COSTS AND REDUCE CUSTOMER BILLS; OVERVIEW OF PECO'S PRINCIPAL ACCOUNTING EXHIBITS AND BUDGETING PROCESS; ELECTRIC SALES FORECAST; EXELON BUSINESS SERVICES COMPANY; AND THE CORPORATE ALTERNATIVE MINIMUM TAX

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
MARISSA HUMPHREY

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Marissa Humphrey. My business address is 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Vice President, Chief Financial Officer and Treasurer. In that capacity, I am responsible for PECO's financial function, including budgeting, long-range financial planning, financial analysis and reporting, project evaluation, and financings. In addition, I have oversight and coordination responsibilities for PECO's accounting, tax, treasury, investor relations, and risk management activities, and I monitor the Company's financial performance to ensure that PECO complies with its financial internal controls and management discipline.

3. Q. Please briefly describe your educational background and professional experience.

A. I hold a Bachelor of Arts degree in Biology from Brown University and a Master of Business Administration from Duke University Fuqua School of Business. I joined Constellation Energy in 2007, working in Corporate Finance, and have advanced through a number of positions at Constellation, Baltimore Gas & Electric ("BGE"), Exelon Business Services Company ("EBSC"), Pepco Holdings

("PHI"), and PECO. Prior to and following the 2012 merger of Exelon and Constellation, I was named Director of Financial Planning & Analysis ("FP&A") at BGE. Beginning in 2014, I served as the Exelon Project Management Officer for the Exelon/PHI merger and, upon the closure of that merger in 2016, I was promoted to Vice President of PHI FP&A. After three years, I transitioned to Vice President of the Exelon Utilities Finance team, and in 2020 I was named Vice President of Regulatory Policy & Strategy at PHI. In 2022, I was promoted to Senior Vice President, Chief Financial Officer and Treasurer of PECO. Prior to joining Constellation Energy, I worked for several years in consulting and healthcare finance.

4. Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to: (1) briefly explain PECO's need for rate relief; (2) summarize PECO's efforts to control costs and reduce customer bills since the Company's last approved electric base rate increase in 2021; (3) provide an overview of PECO's principal accounting exhibits, as well as its budgeting process; (4) describe the Company's electric sales forecast; (5) describe the nature and allocation of costs for services that PECO receives from EBSC; and (6) discuss the Corporate Alternative Minimum Tax.

II. NEED FOR RATE RELIEF

5. Q. Why is PECO seeking a rate increase at this time?

A. As detailed in the testimony of Company witness Nicole L. LeVine (PECO Statement No. 1), PECO is the largest combined electric and natural gas utility in the Commonwealth. PECO's electric operations include thousands of miles of

underground distribution cable, aerial distribution lines, and higher-voltage transmission lines, and PECO operates and maintains 440 power substations. It takes considerable expertise and significant capital investment and operations and maintenance activities to provide PECO's customers with safe and reliable service. Further, PECO continuously strives to improve its system reliability and safety, customer service, and service offerings to meet evolving customer expectations and needs.

Since PECO last requested a base rate increase for its electric operations in March 2021, PECO has continued to make substantial investments in new and replacement utility plant. Between January 1, 2023 and December 31, 2025, the end of the fully projected future test year ("FPFTY") in this filing, PECO will have invested over $3.5 billion in additional electric distribution plant. Continued investment in PECO's electric distribution system is needed to safely and reliably serve customers; the cost of doing so, however, has increased significantly. As detailed further below, inflation and interest rates have risen at a historic pace, which has raised the cost of investment and continues to increase the Company's labor, contracting, and materials expense. The Company has actively worked to mitigate the impact of these increased costs, constraining controllable cost increases below the rate of inflation. However, as explained in further detail below and in the testimony of Company witness Paul R. Moul (PECO Statement No. 5), without an increase in revenues, PECO's overall returns on capital and common equity will be inadequate, impairing the Company's ability to continue making the reasonable and prudent investments necessary to serve customers.

6. Q. Please provide an overview of the significant capital investments made by the Company since its prior rate request, and the investments planned through December 31, 2025.

A. The Company invested $1.0 billion into its electric distribution system in 2023 and is planning to invest an additional $2.5 billion between January 1, 2024 and December 31, 2025. This will result in investments totaling $3.5 billion since the end of the FPFTY in the Company's prior electric base rate case, which ended December 31, 2022. These investments undergo a thorough review and approval process as further explained below in Section IV and in Ms. LeVine's testimony regarding the Company's capital investment planning process.

As discussed in detail in Ms. LeVine's testimony, the Company's capital investments are focused on corrective maintenance, system performance, capacity expansion, facility relocation, new business, information technology ("IT"), and customer operations. Many of these investments are made in coordination with the goals and requirements of PECO's Long-Term Infrastructure Improvement Plan.

7. Q. What is driving the increase in the Company's operating and maintenance ("O&M") costs since its last electric base rate case?

A. The increased O&M costs are driven in large part by historically high inflationary rates, which have caused a significant increase in the Company's labor, contracting, and materials expense. O&M costs have also grown as additional plant has been placed in service that requires ongoing maintenance. In addition, and as detailed in the testimony of Ms. LeVine, the Company is incurring

additional costs to enhance reliability, increase corrective maintenance, address higher storm costs, and focus spending on vegetation management programs and improvements in customer service and offerings. PECO, however, continues to actively manage its costs to mitigate the impacts of significantly elevated inflationary pressures on customer bills and, where possible, seeks to implement activities that will reduce overall expenditures.

8. Q. Please describe the inflationary pressures PECO is experiencing in greater detail.

A. Since the Company's last electric rate case filing in 2021, the United States has experienced an unexpected, sustained, and significantly elevated rate of inflation – the highest in forty years.[1] As a result, actual inflation has greatly exceeded the inflationary impacts assumed in the Company's prior electric rate case. The Company expected inflation to range from 0.8% to 1.7% over 2021-2023. Instead, inflation spiked significantly, reaching 7.8% in 2022 and averaging 5.5% over that three-year period.[2] As a result, PECO has faced steadily increasing costs, including material prices, contracting rates, and borrowing costs. The inflationary pressures have also significantly pushed up prevailing interest rates as shown by the increase in the thirty-year Treasury yield that serves as a risk-free benchmark rate in many financial products, including thirty-year maturity bonds

[1] *See* Databases, Tables & Calculators by Subject, Consumer Price Index for All Urban Consumers (CPI-U), All items in Philadelphia-Camden-Wilmington, PA-NJ-DE-MD, all urban consumers, not seasonally adjusted, U.S. Bureau of Labor Statistics, https://data.bls.gov/timeseries/CUURS12BSA0?amp%253bdata_tool=XGtable&output_view=data&include_graphs=true.

[2] The average 5.5% inflation rate was calculated as the average of the inflation rates in 2021 through 2023 (4.1%, 7.8%, and 4.7%, respectively) per the Consumer Price Index for All Urban Consumers ("CPI-U") for Philadelphia, Pennsylvania.

that are typically issued by utility companies. From a low of 1.66% as of January 4, 2021 to 4.45% as of February 16, 2024, 30 Year Treasury rates have increased at one of the fastest paces in the past thirty years.[3]

9. Q. How has the high inflation environment impacted the Company's borrowing costs?

A. The rise in inflation has directly impacted the Company's borrowing costs. The cost to fund the Company's investments has increased significantly since the Company's last electric base rate case. As stated above, interest rates have increased since the Company's last rate case at one of the fastest paces in history, reaching the highest point in well over ten years.[4] These interest rate increases have pushed up the Company's average cost of borrowing from 3.93% in 2022, as documented in the Company's prior electric rate case filing, to 4.58% forecasted for 2025. The Company's cost of debt is further detailed in the testimony of Mr. Moul.

10. Q. Please provide an overview of the Company's sales since its last electric base rate case.

A. Despite the need to incur increased costs to maintain safe and reliable service for its customers and, where possible, improve such service, the Company expects nearly flat sales in the near term. The Company's number of customers is forecasted to increase by an average of 0.4% per year between 2022 and 2025.

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[3] *See* 30 Year Treasury Rates listed at Daily Treasury Par Yield Curve Rates, U.S. Department of the Treasury, https://home.treasury.gov/resource-center/data-chart-center/interest-rates/TextView?type=daily_treasury_yield_curve&field_tdr_date_value=all.

[4] *Id*.

This increase, however, is partially offset by a decline in usage per customer due, in significant part, to PECO's successful implementation of its energy efficiency and conservation ("EE&C") program pursuant to Act 129 of 2008 ("Act 129"), resulting in only 0.2% annual sales growth. This modest growth in sales and customers does little to offset the necessary investments the Company must make in its system and the rising cost to operate and maintain it.

11. Q. Are there other increased costs you would like to highlight?

A. Yes. As discussed in Company witness Jacqueline F. Golden's testimony (PECO Statement No. 10), in December 2022, PECO implemented a new Customer Assistance Program ("CAP") Percentage of Income Payment Plan ("PIPP"). The PIPP program provides eligible customers with a substantially higher discount than was previously available under PECO's CAP Fixed Credit Option design. While this has the unquestionable benefit of providing greater affordability to PECO's customers that are most in need, the program expansion has significantly increased its cost.

12. Q. How have the Company's increased expenditures impacted its rate of return in invested capital?

A. Without an increase in revenues, PECO's electric operations are projected to produce an overall return on investment capital of 4.43%, and a return on common equity of 4.31%, during the twelve months ending December 31, 2025.[5] As explained by Mr. Moul, such levels of return are inadequate under any

[5] *See* PECO Exhibit MJT-1, p. 1.

reasonable standard and below the rates of return generally afforded to public utilities. Absent a rate increase, the erosion to PECO's projected returns would impair the Company's ability to make all of the reasonable and prudent investments in electric distribution infrastructure that are necessary to maintain and enhance the provision of safe, reliable, and resilient electric distribution service to its customers. Inadequate returns would also negatively impact PECO's credit-coverage ratios and its ability to maintain its investment-grade credit ratings, thereby increasing the Company's financing costs, and ultimately the cost to customers, as further detailed below.

13. Q. Why is it important for PECO to maintain its investment-grade credit rating and minimize its borrowing costs?

A. Maintaining PECO's investment grade credit ratings is important to reducing customer costs. PECO projects that it will need to invest approximately $2.5 billion in electric distribution plant between January 1, 2024 and December 31, 2025. A meaningful portion of these planned investments will be financed with debt and other forms of capital. The Company's credit ratings will impact the cost it will need to pay to attract such capital, and ultimately such costs will be borne by PECO's electric customers. Therefore, it is important that the Company maintain its favorable credit metrics in order to minimize customer costs.

III. PECO'S EFFORTS TO CONTROL CUSTOMER COSTS AND REDUCE CUSTOMER BILLS

14. Q. Please describe PECO's efforts to control customer costs and reduce customer bills.

A. PECO works to minimize financial impacts to customers in two ways. First, PECO diligently manages its own expenses to minimize costs for which customers will ultimately be responsible. Second, PECO has implemented customer programs and makes investments that result in customers incurring lower overall energy costs.

15. Q. Have these efforts negatively impacted PECO's service to customers?

A. Absolutely not. While PECO has undertaken efforts to control customer costs, it has done so in a manner to maintain the same level of safe and reliable service our customers expect, and, where possible, improve such service.

16. Q. What are some examples of PECO's efforts to control its costs?

A. The Company (i) actively works to minimize its O&M expenses, including by making investments in technology and equipment to reduce costly repairs on aging infrastructure and deliver other operational efficiencies; (ii) actively manages its employee-related expenses; (iii) works to reduce its financing costs to obtain the lowest rates available; (iv) pursues governmental funding opportunities to offset costs that customers would otherwise be responsible for; and (v) utilizes the EBSC to improve efficiencies and lower its costs. Indeed, as discussed further below, the Company benefits from the EBSC's procurement opportunities and economies of scale in many specialized services. Additionally, and as discussed

in Section IV below, PECO has rigorous cost-control processes that it performs on a monthly and annual basis to ensure that its spend is aligned with its operational plan.

17. Q. Please describe PECO's efforts to control its O&M expenses in further detail.

A. PECO actively manages its O&M expenses while maintaining, and, where possible, improving, high levels of reliability and customer service in the face of evolving customer expectations. PECO works proactively to identify initiatives to further improve productivity through best practices across the organization, leveraging new technologies, and improving efficiency.

In addition, and as described in Section IV of my testimony, PECO actively manages the creation of its budget, taking reasonable and prudent steps to minimize its O&M expenses and mitigate inflationary impacts on its customers. Notably, PECO's projected annual O&M growth rate since 2022 is 25% lower than the recent average 5.5% inflation increase in the Consumer Price Index. The Company's projected O&M growth rate is 4.1% when adjusted for storms and "make-ready" work requested by third parties. While this growth rate is higher than in recent years, customers continue to benefit from PECO's efforts to keep that growth rate well below increases in the Consumer Price Index.

18. Q. What steps has PECO taken to manage its employee benefit costs?

A. PECO actively manages its employee benefit costs to achieve savings to the maximum extent practicable. The Company does this by evaluating trends in benefits and identifying and implementing cost-reduction measures while

maintaining competitive compensation and benefit packages to successfully attract and retain employees. As an example, the Company has actively taken initiatives to manage its healthcare costs, which nationally have been trending above the rate of inflation.

The Company has a self-insured healthcare program for employees. Therefore, the Company's projected cost increases are based on assumed employee participation, administrative costs, and actual claims experience trended to the next year based on projected medical-price inflation. The Company engages Willis Towers Watson, a national health plan consulting firm, to complete the actuarial underwriting for its health plans in order to set premiums and determine the cost projections.

PECO has undertaken several initiatives to manage its medical rates, i.e., medical cost per employee, including collaborating with our vendor partners to offer population health management programs such as a diabetes program for high-risk members; promoting lower-cost care options, including behavioral telehealth visits and virtual physical therapy sessions; implementing utilization management guidelines for our prescription drug formulary; conducting plan audits to ensure contract compliance; and obtaining competitive contract renewals. For example, in 2023 the Company completed a detailed review of its pharmacy benefit manager (prescription drug benefit), as well as the pricing models and contract terms existing in the market, to ensure that the Company receives competitive coverage and pricing. This process resulted in projected premium savings that are being shared between the Company and its employees to help offset increases in

medical plan rates. As a result of this initiative and other cost-management strategies, the Company expects its 2024 projected medical care cost trend of 5% to remain well below the 8.9% national-average increase projected by Willis Towers Watson and below the near 7% increase projected for the medical plans disclosed in the 2024 survey of health plan cost trends by The Segal Group, Inc.[6]

19. Q. What steps has PECO taken to minimize its borrowing costs?

A. PECO works closely with its banking partners to understand market conditions at the time of issuance of debt to determine what tenor and timing will ultimately generate the most investor demand, thereby securing a lower interest cost for the benefit of customers. In June 2023, PECO successfully priced a $575,000,000, ten-year first mortgage bond ("FMB") offering at a spread of 120 basis points over the ten-year U.S. Treasury for an all-in coupon rate of 4.90%. The deal was well received by investors and the strength of PECO's name and credit profile continue to drive strong investor demand, permitting PECO to tighten the credit spread from the initial launch. The transaction resulted in the third lowest credit spread (i.e., 120 basis points) and fifth lowest coupon for ten-year FMB utility transactions in 2023 at the time of issuance. Additionally, instead of issuing thirty-year bonds in 2023, in light of the unusually high Treasury rates, the Company opted for a ten-year bond to reduce interest expense borne by customers.

[6] *See* 2024 Global Medical Trends Survey, Willis Towers Watson, https://www.wtwco.com/en-se/insights/2023/11/2024-global-medical-trends-survey; What Are the Projected Health Plan Cost Trends for 2024? The Segal Group, Inc., https://www.segalco.com/consulting-insights/2024-health-plan-cost-trend-survey#:~:text=Key%20health%20plan%20cost%20trend%20survey%20findings&text=Per%2Dperson%20cost%20trend%20for,drugs%20replacing%20lower%2Dcost%20therapies.

20. Q. Has the Company pursued any governmental sources of funding to lower customer costs?

A. Yes. PECO continually seeks opportunities that can lower customer costs. For example, and as described further in the testimony of Ms. LeVine, PECO was selected for an award under the Department of Energy's Grid Resilience and Innovation Partnerships ("GRIP") program at the maximum funding level of up to $100 million, subject to negotiation of terms and conditions with the Department of Energy. The GRIP award will be utilized to reduce the cost to PECO's customers of making significant investments in PECO's infrastructure to improve and modernize the grid and enhance reliability.

21. Q. How has PECO assisted customers in lowering their electricity usage and energy costs?

The Company supports programs and investments to help customers reduce their overall energy usage and costs. PECO is now in the third year of the fourth phase of its EE&C Program. As described in further detail in the testimony of Ms. LeVine, the EE&C Program has yielded considerable benefits to customers by helping them to save energy. Since the beginning of the current phase of its EE&C Program, PECO has helped customers save more than 545,045 megawatt hours of energy. In addition, these efforts have resulted in millions of dollars in energy-efficiency work being completed at no cost for low-income customers.

22. Q. What other programs does PECO have to support its low-income customers?

A. In addition to its EE&C offerings, PECO has a suite of low-income-focused programs available to better support the Company's most vulnerable customers.

As discussed in more detail in Ms. Golden's testimony, PECO has:

- Implemented a new CAP PIPP program as of December 2022, providing eligible customers with a fixed maximum monthly bill equal to what the CAP customer can afford for utility service (subject to further program requirements). This program provides a substantially higher discount to customers than was previously available, thereby reducing CAP customers' bills.
- Proposed to change the maximum allowable Matching Energy Assistance Fund ("MEAF") grant in order to expand the impact of MEAF and increase the number of customers eligible for the program.
- Continued to conduct outreach and education to customers regarding the Low-Income Home Energy Assistance Program ("LIHEAP"), a Federally-funded grant program that provides supplemental payments to eligible customers' accounts, and supports its customers seeking LIHEAP grants.
- Proposed an expansion to its communications efforts to connect more customers with available assistance, including LIHEAP, CAP, and other residential customer offerings.

IV. OVERVIEW OF PECO'S PRINCIPAL ACCOUNTING EXHIBITS AND BUDGETING PROCESS

23. Q. Please provide an overview of PECO's principal accounting exhibits.

A. PECO's principal accounting exhibits are Exhibits MJT-1, MJT-2, and MJT-3, which represent PECO's revenue requirement for the FPFTY, future test year

("FTY"), and historical test year ("HTY"), respectively, and are sponsored by Company witness Michael J. Trzaska (PECO Statement No. 3). Exhibit MJT-1 includes PECO's claimed measures of value (i.e., rate base), basic accounting data, a detailed development of the major components of the Company's rate base claim, detailed adjustments required to place FPFTY revenues and expenses on a ratemaking basis, and a discussion of FTY and HTY data. As explained by Mr. Trzaska, Exhibits MJT-2 and MJT-3 follow a similar format, and each of the three exhibits is based, in part, upon data provided by other PECO witnesses.

24. Q. Please describe PECO's budgeting process.

A. One of the key goals of the annual planning process is to integrate and align PECO's operational, regulatory, and financial plans. The operational plan includes goals focused on achieving at least top quartile safety performance, reliability, and customer satisfaction. The operational plan is also consistent with statutory and Pennsylvania Public Utility Commission ("Commission")-imposed regulatory requirements. The Company sets spending targets in its financial plan to achieve its operational goals and comply with such regulatory requirements. As I explained earlier, the Company attempts to minimize its O&M expenses to the extent possible and has generally been successful in controlling these expenses at a lower compound annual growth rate than the rate of inflation.

The planning process starts with a review and update of PECO's operational and regulatory goals and initiatives to determine if changes are required for the future. Any significant changes in such goals and initiatives are taken into consideration when updating the Company's Long Range Plan ("LRP"). The LRP consists of a

five-year outlook and is updated with key assumptions (e.g., inflation rates, interest rates) and with detailed input provided by "responsibility areas" (e.g., Electric Operations and Customer Operations). Each responsibility area reviews its historic expense levels, current and anticipated employee staffing levels, performance assessments, regulatory requirements, operational goals, specific projects, and other factors and develops a responsibility area-specific LRP. The individual responsibility area LRPs are typically submitted for review by each department in June of each year and are carefully analyzed for consistency, completeness, and appropriateness. The responsibility area LRPs are then consolidated into a single LRP and delivered to PECO's senior management (i.e., the Chief Executive Officer, Chief Operating Officer, and Chief Financial Officer) for review and approval in September.

Once that LRP has been updated and approved, its data is thoroughly scrutinized to formulate a detailed two-year budget. The two-year budget is developed by responsibility area, similar to the LRP process described above. The Company then develops its financing plan to ensure that PECO can maintain investment-grade credit ratings. Based on that plan, PECO determines the amount it can borrow to fund its spending plans and the dividend levels that will achieve its targeted capital structure. The consolidated budget is then submitted to PECO senior management for review and approval. The PECO board reviews and approves the Company's capital, O&M, dividend, and financing plan annually.

25. Q. Is that the end of the process?

A. No. Although the budget, as approved, remains in place throughout the year and

is not formally amended, it is reviewed and updated on a monthly basis to reflect estimates derived from the Company's latest data. Actual results are then compared to both the original budget and the latest estimates. Any significant variances are thoroughly investigated to determine why the Company's actuals have departed from its estimated budget and actions are taken as appropriate.

26. Q. Do the personnel in each of the responsibility areas develop their budgets by Federal Energy Regulatory Commission ("FERC") account?

A. No, the responsibility areas do not budget by FERC account. Rather, the responsibility area budgets are prepared on the basis of business activities (i.e., GAAP[7] basis) and related cost elements such as payroll, employee benefits, outside services, etc.

27. Q. Has PECO's budgeting process been reviewed by the Commission?

A. Yes. PECO's budgeting process was reviewed by the Commission during its Focused Management and Operations Audit of PECO in 2022 ("2022 Audit").[8] The Commission's auditors found no deficiencies or weaknesses in the way PECO prepares its budgets.

28. Q. Mr. Trzaska presents the budgeted data for the twelve months ending December 31, 2025 on a FERC account basis in Schedules B-2, B-3, and B-4 of Exhibit MJT-1. How were those figures derived?

A. As Mr. Trzaska explains more fully in his testimony, he analyzed PECO's

[7] GAAP stands for generally accepted accounting principles.

[8] *See* Focused Management and Operations Audit of PECO Energy Company, Docket No. D-2021-3023906 (issued July 2022).

recorded FERC account balances for the twelve months ending December 31, 2023 to determine their composition (e.g., payroll, benefits, rent) and then distributed the FPFTY budgeted costs to the appropriate FERC account based on his findings. The results of Mr. Trzaska's proposed distribution of costs were then reviewed and confirmed with members of my staff.

29. Q. Do Exhibits MJT-1, MJT-2, and MJT-3 contain all of the data needed to evaluate PECO's claimed revenue requirement?

A. No. While MJT-1, MJT-2, and MJT-3 present, in considerable detail, the Company's rate base, revenue, expense, and tax claims, much of the supporting data is provided in the separately bound volumes comprising the Company's responses to the Commission's rate case filing requirements at 52 Pa. Code §§ 53.52, 53.53, and 53.56 and supplemental data requests issued by the Commission's staff. I note that, consistent with the approach to develop responsibility area budgets on the basis of business activities (GAAP basis) as described above, many of the Company's responses to the filing requirements and supplemental data requests that accompany this rate filing were prepared on the basis of business activities (GAAP basis). As a result, there may be differences between those responses and figures in MJT-1, MJT-2, and MJT-3, which were prepared on a FERC account basis.

30. Q. How does the Company's approach to determining plant additions for rate base reflected in Mr. Trzaska's testimony differ from the capital budgeting process you describe above?

A. With respect to capital budgeting, the Company accounts for capital expenditures

in the period when such expenditures are made. The Company determines plant additions based upon when plant is expected to be placed into service. This can, and often does, differ from the period in which capital spending occurs. In determining plant additions for rate base, PECO included only the plant that it expects will actually be placed in service by the end of the FPFTY. I note, however, that the larger projects with which that plant is associated for PECO's budgeting purposes may show an overall project completion date that is beyond the end of the FPFTY, as components of a project may extend beyond the FPFTY.

31. Q. In Paragraph 21 of the Joint Petition for Settlement of PECO's 2021 electric base rate case, PECO agreed that it would provide comparisons of its actual expenses and rate base additions for the twelve months ended December 31, 2022 to its projections in its 2021 case. Has PECO provided these comparisons?

A. Yes. PECO provided the Commission's Bureau of Technical Utility Services, the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate with an update on its Electric Division's actual capital expenditures, plant additions, and plant retirements by month for the twelve months ending December 31, 2022.[9] As described therein, the Company's actual capital expenditures, capital additions, and retirements were greater than its projections in the 2021 electric base rate proceeding.

[9] *See* Docket No. R-2021-3024601.

With respect to O&M expense, PECO spent $658.7 million in 2022 in comparison to the 2022 budget of $663.9 million provided in the 2021 electric base rate case. The small variance is primarily due to a mild 2022 storm season resulting in lower-than-expected storm costs that allowed the Company to perform additional corrective maintenance and vegetation management work as well as absorb increased bad debt expense.

V. ELECTRIC SALES FORECAST

32. Q. How does PECO develop its electric sales forecast, generally?

A. The electric sales forecasting process uses multiple regression-analysis models that determine the relationship between monthly electric sales and predictive variables, such as weather, economic indicators, energy efficiency, and time of year. The modeled results are evaluated using standard statistical criteria (e.g., the Adjusted R-Squared Score, Mean Absolute Percentage Error, t-statistics, and coefficients) to ensure that there are statistically significant relationships between the dependent and independent variables.

33. Q. How does PECO utilize historical weather data in developing its electric sales forecasts?

A. PECO's electric forecasts utilize "weather normal" assumptions based on weather averages from the prior thirty years. PECO's weather normal assumptions are re-calculated annually using the latest thirty-year period. The Company also utilizes weather normals to normalize historical sales results, which are leveraged to analyze usage trends over time. Out-of-Model adjustments are then made to the modeled forecasts to reflect these trends along with the additional impacts of solar

installations and electric vehicles. The results of the forecast are then compared to prior forecasts for consistency and reviewed with the Exelon Senior Manager of Load Forecasting, the PECO Director of Financial Planning and Business Analysis, and senior management for their approval.

34. Q. What is the economic outlook for the PECO service territory and how does this impact your sales growth expectations?

A. IHS Markit, which is an external vendor that provides economic data to the Company, projects that between 2022 and the end of the FPFTY, annual growth in gross metropolitan product ("GMP") and employment will be 1.8% and 0.8%, respectively.[10] The Philadelphia metropolitan area is coming out of a period of economic recovery, with GMP and employment growing faster than historical trends while facing record-high inflation. Efforts to reduce inflation are expected to slow the economy and ease labor markets in the coming years. This economic outlook is one of several drivers impacting the Company's forecasts.

35. Q. Please describe the results of the Company's sales forecast.

A. Between 2022, the FPFTY in the Company's last electric base rate case, and the end of the FPFTY in this base rate case, the Company forecasts total weather normal electric sales to grow 0.2% annually, with 0.6% annual growth in Residential sales and flat annual growth in Commercial & Industrial sales. Sales will primarily be driven by customer growth, economic growth, and electric vehicle charging, partially offset by energy-efficiency and solar impacts.

[10] Data from IHS Markit for Philadelphia, PA categorized under "Metropolitan level" as of August 2023.

Over the same period, the number of PECO customers is forecasted to grow by 0.4% per year, with 0.5% annual growth in Residential customers and 0.2% annual growth in Commercial & Industrial customers. Based on the Company's sales and customer forecasts detailed above, use per customer ("UPC") during that same period is forecasted to decline by 0.2% per year, with 0.2% annual growth in residential UPC and 0.2% annual decline in Commercial & Industrial UPC.

VI. EXELON BUSINESS SERVICES COMPANY

36. Q. Does PECO procure certain shared services from an affiliated service company?

A. Yes. Like many other energy holding company enterprises, Exelon created a service company, the EBSC, following the merger of PECO and the former Unicom Corporation, to house specific support functions that it believed could be staffed more efficiently and economically on a centralized basis.

37. Q. What types of services does the EBSC make available and to whom?

A. The EBSC is designed to provide a range of what would typically be regarded as in-house services in the case of a stand-alone utility. In broad terms, those services fall into the following categories: IT; supply; finance; human resources; government and regulatory affairs and public policy; legal and corporate governance; utility operations; real estate; executive services; communications; and security. The EBSC offers its services to PECO and other affiliated members of the Exelon family of utility companies, which include Atlantic City Electric Company, Baltimore Gas and Electric Company, Commonwealth Edison

Company, Delmarva Power & Light Company, and Potomac Electric Power Company.

38. Q. Is PECO required to utilize the EBSC's services?

A. No, PECO is not required to use the EBSC's services. Under the terms of the General Services Agreement ("GSA") between PECO and the EBSC, which was approved in the PECO/Unicom merger proceeding at Docket No. A-110550F0147, PECO has the discretion to determine whether and to what extent to utilize the EBSC's services in all areas except corporate governance.

39. Q. What role does the EBSC play in PECO's electric distribution operations?

A. PECO's overall approach is to use its own personnel or independent contractors to staff the day-to-day operations of its electric delivery system, as well as its customer-service functions (e.g., call center and billing services). Other services, such as employee-benefits administration, mass purchasing, insurance, and treasury, to name a few, are provided by the EBSC. Certain highly specialized services, for which it would not be cost effective to maintain the required expertise at either PECO or the EBSC, are obtained through contracting with outside firms.

40. Q. What is the principal advantage of the service company structure?

A. The EBSC enables PECO to realize economies of scale and scope that, in my judgment, could be very difficult to achieve on an individual-company basis. Indeed, if PECO were to try to maintain a full complement of comparably qualified personnel on its own payroll, the total cost PECO would incur to obtain

the same level and quality of service it receives from the EBSC likely would be considerably higher.

41. Q. How does the EBSC price the services it provides to PECO?

A. The GSA provides that the services furnished by the EBSC to PECO are to be billed at the EBSC's cost. Prior to the enactment of the Energy Policy Act of 2005, the Exelon utility companies were subject to the affiliate-transaction and cost-allocation rules prescribed by the United States Securities and Exchange Commission ("SEC") under the Public Utility Holding Company Act of 1935 ("PUHCA"), which generally mandated that service companies, such as the EBSC, offer their services to affiliates at fully distributed cost. The "at cost" rules were incorporated into the GSA, and their continued use in the provision of non-power goods and services has been approved by the FERC, which assumed some of the SEC's oversight responsibilities when PUHCA was repealed, in part, several years ago.

42. Q. How is the cost of services provided to PECO determined?

A. Direct charges are made for services where possible. Otherwise, costs are allocated on the basis of the allocation factors/methodologies identified in the GSA, which were previously reviewed and approved by the SEC. These allocations and methodologies were also reviewed as part of the Commission's 2022 Audit, and the Commission's auditors found no issues with respect to PECO's cost allocation methodology.

43. Q. How does PECO satisfy itself that the services it procures from the EBSC are provided at a competitive price?

A. PECO takes several steps to ensure that the services it procures from the EBSC are provided at a competitive price. First, PECO and the management of EBSC work together to identify PECO's needs and to define service priorities and major new initiatives. As a consequence, PECO has meaningful input into the development of the EBSC's budget for the upcoming year, and I, as PECO's Chief Financial Officer, ultimately approve the service level arrangements ("SLAs"). SLAs are annual agreements between the EBSC and Exelon's operating companies (including PECO) entered into under the express authority of the Commission-approved GSA that detail the specific services that the EBSC will provide during the following year, including the scope of services, unit cost expectations, and performance measures. Services are grouped by function so that budgeted and actual costs can be tracked.

Second, the EBSC's monthly billings are carefully scrutinized by PECO personnel. Variances between actual and budgeted charges are reviewed by PECO personnel with their EBSC counterparts to ensure that all costs are properly justified.

In addition, for functions that are not already outsourced, PECO obtains extensive information regarding the composition of the EBSC's costs, which PECO can then review for reasonableness. This "Market Testing Analysis," developed in conjunction with the Commission's management auditors, is a formal approach for evaluating the cost effectiveness of using the EBSC's shared services. This

analysis is performed on an annual basis, and, along with allocation factors and methodologies used for EBSC costs, was reviewed as part of the Commission's audits of the Company in 2014 and 2022. In 2017, the Commission conducted a Management Efficiency Investigation to evaluate PECO's implementation of recommendations from the 2014 Audit.[11] The Commission again examined PECO's affiliated interest and cost allocations processes and concluded that PECO (and EBSC) had taken steps to verify that "shared services are being provided in an efficient and cost-effective manner and/or improvement opportunities are identified to ensure service offerings are fair and reasonable." PECO has also worked to implement recommendations made by the Commission, including those related to its payroll and accounts payable systems and the sharing of benchmarking reviews among EBSC, PECO, and other Exelon companies.

44. Q. What is PECO's claim in this proceeding for EBSC services?

A. PECO has included $149.7 million in its FPFTY expense claim for charges from EBSC. A breakdown of those costs is attached as PECO Exhibit MH-1.

VII. CORPORATE ALTERNATIVE MINIMUM TAX

45. Q. How does the enactment of the Inflation Reduction Act ("IRA") impact PECO?

A. The IRA implemented a new corporate alternative minimum tax ("CAMT") beginning in 2023 that imposes a 15% tax on adjusted financial statement income

[11] *See* PECO Energy Company Management Efficiency Investigation Evaluating the Implementation of Selected Management Audit Recommendations from the 2014 Focused Management and Operations Audit, Docket No. D-2016-2562303 (August 2017).

("AFSI") on "applicable corporations." Applicable corporations will now be required to pay the greater of 15% of their AFSI or their regular federal tax liability. Based on current tax guidance and forecasted projections, PECO is subject to the CAMT.

46. Q. Is PECO an "applicable corporation" under the CAMT?

A. Yes. The CAMT states that if a corporation's average annual AFSI exceeds $1 billion over the preceding three-year period, then the corporation and its subsidiaries are applicable corporations. Although PECO does not meet that $1 billion threshold on a standalone basis, PECO is a subsidiary of Exelon Corporation. Strictly for purposes of determining if Exelon exceeds the $1 billion in average profits, Exelon must include all of its subsidiaries, including PECO, because Exelon is considered a "single employer group" under the tax rules. If a single employer group in the aggregate exceeds the $1 billion profits threshold, each corporation that is part of that single employer group is considered an "applicable corporation" and separately subject to the CAMT. Under the tax rules, when a subsidiary ceases to be a member of an affiliated group of corporations, the departing subsidiary is entitled to its CAMT credit carryforward and can utilize that credit in future tax years when its regular tax exceeds its CAMT liability.

47. Q. For CAMT purposes, how is AFSI determined?

A. For purposes of calculating AFSI, the starting point is financial statement net income under GAAP. The GAAP financial statement net income is then adjusted for federal income taxes, accelerated tax depreciation, pension and other

postemployment benefits. As a result, for purposes of determining AFSI, federal income taxes, accelerated tax depreciation, pension and other postemployment benefits are treated the same with respect to the calculation of the regular federal income tax liability.

48. Q. Why does PECO's CAMT liability exceed its regular tax liability?

A. Under tax law, certain expenditures capitalized for GAAP financial statement purposes qualify for accelerated tax deductions, such as tax repairs and certain overhead capitalization. As a result, these expenditures are expensed in the calculation of the regular tax liability sooner than for CAMT, which results in a lower regular tax liability than under the CAMT calculation.

49. Q. How does PECO calculate the CAMT?

A. The Company calculated the CAMT based on its standalone separate company books and records.

50. Q. How is the Company expected to account for the CAMT in its financial statements?

A. For income tax accounting purposes, a current income tax liability and current income tax expense will be recorded for the CAMT liability but will be equally offset by recording a deferred tax asset and a reduction to deferred income tax expense to reflect the CAMT credit carryforward. As a result, there is no net incremental income tax expense associated with the CAMT. Corporations are entitled to a tax credit equal to the amount by which the CAMT liability exceeds the regular tax liability. This amount can be carried forward indefinitely and used

in future years when the regular tax liability exceeds the CAMT liability. The credits are not permitted to be carried back to prior years. For income tax accounting purposes, a deferred tax asset is established for the CAMT credit carryforward.

51. Q. Why is it appropriate to include the deferred tax asset related to CAMT in rate base?

A. Accelerated tax deductions related to utility property generate cash tax benefits that reduce the cost of capital. For rate making purposes, rate base is adjusted downward to reflect the lower cost of capital attributable to accelerated tax deductions. The CAMT has the effect of reducing the realization of the tax benefits associated with accelerated tax deductions, such as tax repairs and certain other overhead capitalization adjustments (tax repair and certain overhead capitalization deductions do not reduce CAMT). The Accumulated Deferred Income Taxes ("ADIT") associated with tax repairs and other property-related tax adjustments are included in PECO's rate base as a downward adjustment. Therefore, to reflect the appropriate cost of capital, the deferred tax asset associated with the CAMT credit carryforward should likewise be included in rate base as an adjustment that offsets ADIT.

VIII. CONCLUSION

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

A. Yes, it does.

PECO Exhibit MH-1:

PECO Energy Company Business Services Company Operations and Maintenance Costs

PECO Energy Co. **PECO Exhibit MH-1**
BSC Operations & Maintenance Costs
Presentation Basis: PECO Electric Distribution

($ in millions)

		2025 Budget
1	Legal Governance	7.7
2	Executive Services	12.5
3	Security	9.9
4	Government and Regulatory Affairs & Public Policy	1.3
5	Exelon Utility Operations	9.6
6	Communications	2.1
7	Finance	19.0
8	Human Resources	7.9
9	Real Estate	1.0
10	Supply Services	0.8
11	**Subtotal of Non-IT EBSC**	**72.0**
12	**IT EBSC**	**78.8**
13	Charitable Contributions	0.5
14	Lobbying / Other	0.7
15	**Subtotal of Non-Recoverable Costs**	**1.2**
16	**Total EBSC Charges (excl. Non-Recoverable)**	**149.7**

PECO ENERGY COMPANY
STATEMENT NO. 2-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

REBUTTAL TESTIMONY

WITNESS: MARISSA HUMPHREY

SUBJECT: RESPONDING TO CERTAIN PROPOSED REVENUE REQUIREMENT ADJUSTMENTS

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
MARISSA HUMPHREY

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Marissa Humphrey. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Vice President, Chief Financial Officer and Treasurer. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct testimony marked as PECO Statement No. 2. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will address certain operating revenue and expense adjustments proposed by Bureau of Investigation and Enforcement ("I&E") witness Christine Wilson and Office of Consumer Advocate ("OCA") witness John Defever.

II. CORRECTIONS TO DIRECT TESTIMONY

4. Q. Do you have any corrections to make to your direct testimony?

A. Yes. On page 10, line 13, "25%" should be replaced with "28%," and on page 10, line 15, "4.1%" should be replaced with "4.0%." Support for these corrected figures was provided in the Company's response to OCA discovery request OCA-I-1.

III. RESPONDING TO OPPOSING PARTY ADJUSTMENTS

A. Payroll

5. Q. Please describe Mr. Defever's and Ms. Wilson's proposed adjustments to the Company's payroll expense.

A. The Company's proposed payroll expense was forecasted utilizing a 2% vacancy rate. Mr. Defever proposes applying a 4.4% vacancy rate, and Ms. Wilson proposes applying a 2.75% vacancy rate. Mr. Defever and Ms. Wilson also proposed additional payroll-related adjustments that are addressed in the Rebuttal Testimony of Company witness Trzaska, PECO Statement No. 3-R.

6. Q. Do you agree with Mr. Defever's or Ms. Wilson's proposed vacancy rate?

A. No. Mr. Defever derived his proposed 4.4% vacancy rate by averaging actual vacancies over the five years 2019 through 2023. It would be unreasonable to utilize a simple five-year average of actual vacancies when the Company's ability to hire and retain workers was significantly impacted in and around 2020-2022 by the COVID-19 pandemic. Ms. Wilson recognized this, noting that the Company's data during this period "demonstrates that the vacancy percentages for 2021 and 2022 are elevated due to higher numbers of vacancies post-COVID-19." Ms. Wilson recommended utilizing a 2.75% vacancy rate by using the average vacancy percentage for 2023 alone. While this is a more reasonable approach than the one advanced by Mr. Defever, it should still be rejected. The Company's forecasted head count for the fully projected future test year ("FPFTY") utilizes a 2% vacancy rate, through which the Company is already taking into account the fact that there will always be a certain level of normal vacancies. Applying even an additional 0.75% would unfairly reduce the Company's payroll expense based

on a restrictively small window of historical data when the Company was still impacted by and recovering from lingering impacts of the pandemic.

Notably, it is also inconsistent with the Company's actual vacancy rate, which is only 1.4% through the first quarter of 2024, already below the 2% projected in the FPFTY. The Company currently has 2,215 full-time equivalent employees ("FTEs") and there is a detailed hiring plan in place, putting PECO firmly on track to achieve its projected head count of 2,340 FTEs by December 31, 2024 and 2,373 FTEs by December 31, 2025.

A significant number of the Company's new hires in the future test year ("FTY") and FPFTY will be employees in our field operations ("Field Ops"), directly working on PECO's distribution system. These employees will be essential to completing the Company's planned distribution improvements, maintaining system reliability, and continuing to provide customers with top-quality service. The Company's Field Ops employees are typically hired through PECO's "schools" described below.

The Company's Field Operations schools are held multiple times each year (with the exception of 2020 due to the COVID-19 pandemic). The Company generally holds three Electric Operations Schools on an annual basis: an Energy Technician School, an Aerial Line Mechanic Apprentice School, and an Underground Line Mechanic Apprentice School. The Company also holds schools for substations and testing as needed. Each of these has been scheduled for the FTY (one has already been held), and the Company will hold three schools during the FPFTY. The Company has regularly met its hiring projections from its schools. The

scheduled schools in the FTY and FPFTY are expected to result in over 110 graduates (i.e., FTEs) hired into the Company's Field Ops by the end of the FPFTY.

Each school and its hiring goals are planned based upon current vacancies and forecasted attrition to enable the Company to maintain its required workforce. The schedule and hiring goals of these schools are also planned to align with the Company's Field Ops hiring plan and Electric Operations work plan, which are fundamental to ensuring continued safe and reliable operations, and which also support the Company's Pennsylvania Public Utility Commission ("Commission")-approved long-term infrastructure improvement plan ("LTIIP"). The Company needs to plan years in advance to ensure that it has enough fully trained and experienced employees, some of whom require more than three years of training to implement the Company's work plan and maintain a safe working environment.

As I noted earlier, the Company had to cancel its planned schools in 2020 due to the COVID-19 pandemic. These included an Aerial Line Mechanics school and an Underground Line Mechanics school. The cancelling of these schools, and the pandemic, continued to have impacts into 2021, 2022 and even 2023, which are reflected in higher-than-usual vacancy rates in those years. This also resulted in lower base payroll spending, which Ms. Wilson references on page 23 of her direct testimony. However, what Ms. Wilson did not recognize is that the Company still needed to complete the same level of anticipated work to maintain system safety and reliability in those years, which required the Company to incur other labor costs outside of base payroll spending.

A number of employees will also be hired in the FTY and FPFTY, outside of PECO's schools, to support the Company's customer operations and administrative departments. These employees are expected to primarily support the increases in the Company's work plan, which includes the Commission-approved LTIIP.

B. <u>Incentive Compensation</u>

7. Q. Why did Mr. Defever recommend disallowance of 50% of the Company's incentive compensation plan?

A. Mr. Defever stated that the Company's incentive compensation plan does not appear to provide sufficient motivation to employees and, therefore, does not benefit ratepayers. Mr. Defever also took issue with the fact that, at PECO, all eligible employees have received awards under the Company's incentive compensation plan. He asserted that incentive compensation should only be awarded to employees that show greater effort, and that employee motivation may be reduced if employees assume they will be awarded a bonus.

8. Q. Did Mr. Defever provide any support for his conclusion that the Company's incentive plan does not appear to provide sufficient motivation to employees?

A. No, and I believe his conclusion is directly contradicted by the Company's actual performance, which is detailed in the testimony of Company witness Nicole L. Levine (PECO Statements No. 1 and 1-R).

9. Q: Please explain why recovery of the Company's incentive compensation plan is appropriate.

A. The Company's Annual Incentive Plan ("AIP") and long-term incentive program ("LTIP") (which includes stock-based and cash-based components) are important and valuable components of PECO's total compensation plan. These incentives are common in the utility industry and necessary to attract and retain quality employees needed to operate the Company.

PECO competes for employee talent against other utility companies in the industry and other companies within its service territory, and it is critical that the Company offer comparable and competitive compensation programs to attract and retain experienced and skilled employees. The Company periodically reviews its compensation programs against peer utility groups to ensure we are able to attract and retain experienced and skilled employees. The Company's compensation plans are comparable to those of its peers in the utility industry.

I have been advised by Counsel that similar incentive compensation tools have been expressly permitted by the Commission. *See*, *e.g.*, *Pa. P.U.C. v. Pennsylvania-American Water Company*, Docket No. R-2020-3019369, Opinion and Order (Feb. 25, 2021), p. 53; *Pa. P.U.C. v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597, Opinion and Order (Dec. 5, 2012), p. 26. Additionally, the Commission's 2022 Management Audit of the Company examined PECO's executive compensation and found no issues.

If the Company was unable to offer incentive compensation, it would need to increase its fixed compensation to remain competitive, which could increase payroll expenses even more. The Company determines how its employees should be compensated at each level within the various job categories needed to operate

the Company, and employees' total compensation, inclusive of potential AIP and LTIP awards, is set at that amount. AIP and LTIP are not *in addition* to each employee's compensation amount; rather, they are a part of the total annual employee compensation amount. After determining the appropriate total annual amount that employees should be paid for their work, the Company has a choice – it can either (a) pay its employees a guaranteed annual total compensation amount, or (b) make a portion of that compensation dependent on the overall performance of its employees in key areas designed to benefit customers. Rather than increase base salaries across the board to guarantee a higher level of annual total compensation as set forth in option (a) above, Company leadership has decided that to achieve the best results for customers and the best performance from its employees, a portion of employee salaries should be placed "at-risk," i.e., option (b) above. That "at-risk" portion of annual compensation is the portion represented by AIP and LTIP.

In order to be paid their full potential annual compensation (i.e., to receive the AIP portion, and where applicable, the LTIP portion of their compensation), employees must achieve specific goals that benefit customers through performance. By linking each employee's compensation to the Company's incentive plans, each employee is incentivized to ensure that the Company achieves the highest levels of safety, reliability, and customer service possible. AIP payouts are based on how well the employee, PECO, and Exelon as a whole perform against goals set for the year, which are measured by key performance indicators ("KPIs").

The Company made a deliberate decision to ensure that the incentive plans of all employees have safety, customer satisfaction, reliability, and total operations and maintenance expense levels as key requirements to achieve maximum available compensation, so that all employees are focused on maximizing Company performance in serving customers and minimizing costs. In order to receive total compensation, performance expectations must be met in these critical customer-focused performance categories.

Mr. Defever also appears to not understand, at a basic level, how the Company's incentive compensation plan works. Mr. Defever asserts that every eligible employee always receives an award and that, therefore, the Company's incentive plan does not properly motivate employees. *See* OCA Statement No. 1, p. 11. That is not the case. Individual performance is assessed annually and factored into awards given under the Company's incentive compensation plan through an individual performance multiplier ("IPM"). The IPM can reduce an individual's incentive payout by 50% if they are a limited performer, or even lower for those on performance improvement plans or those who had a "limited impact." Conversely, application of the IPM can reward employees with a payout of up to 120% of their targeted incentive for extraordinary performance. Underperforming employees regularly do not receive their targeted potential incentive, and exceptional employees can receive greater than the target. This component of the Company's incentive plan is specifically designed to differentiate between high performers and lesser performers, to motivate and reward high performance, and is exactly the type of individualized incentive that Mr. Defever stated the Company's incentive plan lacks. Company witness LeVine provides evidence of

the motivating impact of our incentive programs, documented through continued high performance. *See* PECO Statement No. 1 and 1-R.

10. Q: You noted that the Company's AIP and LTIP are factored into an employee's total compensation. Has Mr. Defever challenged the amount that any employees are paid?

A. No. Moreover, it is worth noting that Company leadership goes to great efforts to make sure its employees are compensated appropriately at market rates. If PECO is denied recovery for portions of its employee costs, then PECO will be denied recovery for compensation costs that no party has even alleged to be unreasonable.

C. <u>Supplemental Executive Retirement Plan</u>

11. Q. Did Mr. Defever oppose any other aspects of the Company's compensation?

A. Yes. Mr. Defever proposes disallowing the entirety of the Company's Supplemental Executive Retirement Plan ("SERP"), arguing that the Company has not demonstrated that the SERP has any connection to metrics regarding the provision of utility service and that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

12. Q: Does the Company agree with Mr. Defever's proposed disallowance of SERP expense?

A. No. The SERP is similar to the Company's other post-employment benefit expenses – the main difference being that **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**. Mr. Defever is wrong in concluding that the SERP does not benefit PECO's customers. There are currently **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The SERP is a part of these employees' overall compensation and is important to retaining them in a competitive market, ensuring smooth and safe operations. A study performed by Willis Towers Watson in 2023 revealed that of the 27 utilities surveyed, all of them provide non-qualified benefits to address benefits limited by the IRC. It is important to PECO, and a benefit to customers, that these key employees remain employed at PECO. The SERP, therefore, benefits PECO's customers.

D. <u>Severance</u>

13. Q: Please describe Mr. Defever's and Ms. Wilson's reasons for disallowing the Company's severance expense.

A. Mr. Defever asserts that the Company's severance expense should be borne by shareholders since ratepayers should not be responsible for the costs of employees no longer providing utility service. Mr. Defever also noted that the Company does not plan to terminate employees in the FPFTY. However, termination decisions are typically made within a short window based upon performance and, therefore, it would be highly unusual for a company to have long-term plans to

terminate specific employees. Ms. Wilson noted that Exelon Business Service Company ("EBSC") costs are either billed direct costs or allocated to the Company based on ratios such as a revenue-related ratio, expenditure-related ratio, labor/payroll-related ratio, units-related ratio, asset-related ratio, or a composite ratio. Similar to Mr. Defever, Ms. Wilson claims that since severance expense would not be a direct cost to the provision of safe and reliable service, it is inappropriate for PECO to claim an allocated portion of EBSC employees' severance expense for ratemaking. Ms. Wilson also notes that no employee time or services are provided for the payment of severance expense and that there is no actuarial study available for the basis of the Company's FPFTY claim.

14. Q: How do you respond?

A. EBSC employee cost is allocated to PECO based on, among other things, (i) the time employees spend assisting PECO and (ii) the Modified Massachusetts formula. Neither Ms. Wilson nor Mr. Defever disputes how these costs are allocated. PECO's utilization of EBSC employees provides significant savings to the Company in business areas including information technology, supply, commercial operations, finance, human resources, government, external affairs, public policy, legal, corporate governance, strategy, and communications. PECO obtains the services of these employees, per its Service Level Agreement with EBSC, at competitive rates that have generated significant savings to customers. As noted earlier in my testimony, PECO operates in a competitive environment to recruit and attract talented individuals to join its team. The same is true for EBSC, which, in turn, offers the services of its employees to PECO and its affiliated regulated utilities. PECO shares in the compensation of these EBSC

employees and part of the overall compensation plan provided to certain EBSC employees (to be competitive in the market) is a severance program for certain involuntary separations, allowing the Company to efficiently terminate low performers and upgrade talent when necessary, which helps improve overall Company performance, benefitting customers. PECO has the benefit of the services provided by such EBSC employees at cost, and PECO should also share in such employees' "total compensation plan," which may include severance. Such severance expenses are directly related to the provision of utility service since they enable EBSC to competitively hire and retain individuals who provide service to PECO. "Total compensation" is regularly reviewed to ensure that employees receive competitive salaries, but not more than the market dictates. Moreover, the Commission recently reviewed the Company's compensation and allocation of EBSC costs to PECO in the Company's 2022 Management Audit, finding no issues with such compensation.

The Company's FPFTY proposed severance expense is reasonable and based on historical expense and estimates. Between 2018 and 2023, the Company averaged about $1.3 million in actual severance expense annually and has incurred no less than $948,000 of severance expense in any recent year. In contrast, the Company has only budgeted $495,000 and $510,000 in the FTY and FPFTY, respectively, and believes this is a reasonable estimate since it is significantly less than that experienced in any year in recent history and recognizes that severance expense will be incurred in any given year.

E. Board of Directors and Directors and Officers Liability Insurance

15. Q: Why did Mr. Defever propose a 75/25 sharing of the Company's Board of Directors expense and Directors and Officers ("D&O") Liability Insurance between shareholders and ratepayers?

A. Mr. Defever asserts that the Board of Directors serve the interest of shareholders and, therefore, shareholders are the primary beneficiaries of these costs. Mr. Defever similarly claims that shareholders are the primary beneficiaries of the Company's D&O Liability Insurance since D&O insurance protects PECO and its officers from lawsuits that arise as a result of their decisions and actions, and such lawsuits are often brought by the Company's shareholders.

16. Q: Do you agree with Mr. Defever's characterization of the Board of Directors, or that shareholders are the primary beneficiaries of the Company's D&O Liability Insurance?

A. No. The Board plays a critical role in supporting the Company and its customers. The Board's responsibilities and its role are set forth in its Corporate Governance Principles, which state:

> The Board is primarily responsible for overseeing the Company for the long-term benefit of the Company's shareholders and the employees, customers and communities served by the Company and its subsidiaries. The Board's responsibilities include, but are not limited to, oversight of the Company's development and execution of strategy and long-range business plan; business operations and performance, including safety and reliability; capital structure and capital allocation, including financing and investments; enterprise risks, including commodity markets, market design, enterprise security (physical and cyber), operating risks, and financial performance; executive compensation; customer experience; corporate citizenship, including sustainability and environmental stewardship, reputation, social responsibility, and ethical business practices; the lobbying, political contributions, and political activities

> of Exelon and its subsidiaries; and governance practices. The Board and its committees (each, a "Committee") select and oversee senior management, which is responsible for managing the business of the Company under the direction of the Board. In fulfilling its responsibilities, members of the Board provide sound stewardship through informed business judgment and exercising fiduciary duties of good faith loyalty and care. In so doing, directors may rely upon the recommendations of Committees, subsidiary boards of directors, management, outside advisors, and independent auditors.[1]

In other words, the Board effectively oversees and advises the Company on all areas of performance, and it is essential to PECO's customers that the Company performs well – especially in areas such as the execution of the Company's long-range business plan and safety and reliability. In addition, strong corporate governance is critical to effectively managing the Company for the benefit of all stakeholders, not just shareholders. Mr. Defever's proposed 75/25 cost sharing ignores the importance of the Board in protecting customer interests.

Furthermore, D&O liability insurance is a necessary and unavoidable expense. The purpose of D&O insurance is twofold. First, it enables the Company to attract and retain talented, competent directors and officers to oversee the conduct of the business and effectively carry out their responsibilities for the benefit of customers with the protections afforded by the insurance program. Second, D&O insurance provides a significant source of balance sheet protection, thereby safeguarding the Company from financial distress and preserving capital for uses that ensure the safe and reliable delivery of service to customers. Therefore, it is a necessary and prudent cost of providing service to customers and, as such, should be fully recoverable by the Company.

[1] Exelon Corporate Governance Principles (Approved April 30, 2024), https://www.exeloncorp.com/content/dam/exelon/company/Documents/EXC_CorporateGovernancePrinciples.pdf.

Mr. Defever also cites no support for his allegation that shareholders often sue the Company and its officers.

F. Corporate Aircraft

17. Q: Mr. Defever proposed disallowing the entirety of the Company's corporate aircraft expense. How does the Company respond?

A. Corporate aircraft are utilized on occasion by the Company's senior executives and Board of Directors. On certain occasions, other senior employees may also travel on corporate aircraft with senior executives and Board members to reduce expenses and ensure the aircraft are utilized to the maximum extent possible.

Given the volume and frequency of travel that we expect of our executives, this use of corporate aircraft is considered both a time efficiency and a security benefit.

Corporate aircraft provide these executives and Board members flexible travel times and allow them to maximize efficiencies and the time they are able to devote to the Company. It is also often difficult for Company senior leaders and Board members to work and collaborate together on commercial flights because of sensitive-information restrictions under various governmental regulatory regimes (e.g., NERC, CIP, NRC, FERC). They have no restrictions on corporate aircraft on meeting, planning, and working with each other. Thus, productivity en route is greatly enhanced since employees can discuss proprietary information aboard corporate aircraft in a secure environment. Corporate aircraft also provide these executives and Board members with needed flexibility to maximize efficiency and the time they are able to devote to the Company. This flexibility also allows them to quickly change travel plans when needed to respond to

emergent issues, to avoid potential delays or other incidents that could affect attendance at critical events, and to travel to several locations on a single trip.

G. <u>Storm Expense</u>

18. Q: Mr. Defever and Ms. Wilson both proposed adjustments to the Company's proposed storm expense. Is there any aspect of their proposed adjustments that you would like to address?

A. Yes. Company witness Trzaska addresses arguments raised by Mr. Defever and Ms. Wilson in his rebuttal testimony, but I would also like to address Mr. Defever's and Ms. Wilson's opposition to the Company utilizing an inflation adjustment to calculate its FPFTY storm expense. Neither Mr. Defever nor Ms. Wilson disputes the fact that the average cost of both labor and non-labor (such as material and equipment) has been increasing in the past five years and it will continue to increase during the FTY and FPFTY. I detailed in my direct testimony how inflation and interest rates have risen at a historic pace, which has raised the cost of investment to the Company and continues to increase the Company's labor, contracting, and materials expense. It is a well-known fact that with the increased cost of labor and non-labor, the Company will have to spend more money in the future to restore the same amount of storm damage than in the past. As explained by Company witness Trzaska in PECO Statement 3-R, the Company utilized a regional consumer price index ("CPI") when calculating storm expense. The CPI is a measure that examines the weighted average of prices of a "basket" of consumer goods and services, such as transportation, food, and medical care. It is calculated by taking price changes for each item in the predetermined basket of goods and averaging them. The CPI is one of the most

frequently used statistics for identifying periods of inflation or deflation. I agree with Mr. Trzaska that the CPI is known and measurable and that it is reasonable to utilize a CPI factor when calculating its FPFTY storm expense.

IV. CONCLUSION

19. Q. Does this complete your rebuttal testimony at this time?

A. Yes. It does.

So BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2024-3046931**
	:	
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Marissa Humphrey, hereby state that I am the Senior Vice President, Chief Financial Officer and Treasurer for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 2
- PECO Exhibit MH-1

- PECO Statement No. 2-R (Public and Confidential Versions)

Dated: August 5, 2024

Marissa Humphrey

PECO Statement No. 3:

Direct Testimony of Michael J. Trzaska

PECO ENERGY COMPANY
STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

DIRECT TESTIMONY

WITNESS: MICHAEL J. TRZASKA

SUBJECT: PRESENTING PECO'S OVERALL REVENUE REQUIREMENT; CERTAIN RATEMAKING ADJUSTMENTS; STORM RESERVE ACCOUNT; AND SURCHARGE RATE CREDITS

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
MICHAEL J. TRZASKA

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Michael J. Trzaska, and 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 Rate Specialist in the Regulatory Policy and Strategy Department. My duties and responsibilities in that capacity include performing financial analysis, project management and regulatory strategy for gas and electric operations throughout the Company's service territory. I am responsible for providing expert testimony on behalf of the Company with respect to various regulatory issues.

3. Q Please describe your educational background.

A. I earned a Bachelor of Science degree in Accounting from Drexel University in 1987 and a Master of Science in Finance degree from LaSalle University in 1996.

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

A. Upon graduation from Drexel University in 1987, I was hired by PECO and have been with the Company since that time in various positions of increasing responsibility.

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

A. The principal purpose of my direct testimony is to explain the preparation and presentation of data supporting PECO's request for a general base rate increase for its electric distribution operations. More specifically, I explain how the components of the Company's overall revenue requirement were developed. This includes certain portions of the claimed measures of value and the pro forma ratemaking adjustments that were made to calculate the Company's revenue requirement based on data for a fully projected future test year ending December 31, 2025 ("FPFTY"), a future test year ending December 31, 2024 ("FTY"), and a historic test year ended December 31, 2023 ("HTY"). For purposes of supporting PECO's proposed increase in base rate distribution operating revenue under its proposed rates, the Company is relying principally upon data for the FPFTY.

I will also describe the Company's proposal to establish a Storm Reserve Account in this case. In addition, I will discuss the amounts PECO received for past use of its fiber network and for the amounts recorded to the regulatory asset account for incremental COVID-19 uncollectible expense (the "COVID-19 Regulatory Asset") that are reflected in PECO's current rates established in its 2021 electric base rate case.[1] These amounts will be credited to customers in 2025 through the surcharge mechanisms described by Company witness Megan A. McDevitt (PECO Statement No. 8).

[1] *See Pa. P.U.C. v. PECO Energy Co. – Elec Div.*, Docket No. R-2021-3024601 (Recommended Decision issued Oct. 6, 2021), pp. 7, 19, 31. The Recommended Decision was approved by the Commission without modification by its Order entered on November 18, 2021 ("2021 Rate Case Order").

6. Q Are you sponsoring all or portions of any exhibits in this proceeding?

A. Yes. I am sponsoring PECO Exhibits MJT-1, MJT-2, and MJT-3. PECO Exhibits MJT-1, MJT-2, and MJT-3 comprise PECO's principal accounting exhibits for the FPFTY, the FTY, and the HTY, respectively.[2] The base data for the FPFTY that I used to develop PECO Exhibit MJT-1 were derived, for the most part, from PECO's capital and operating budgets for the twelve months ending December 31, 2025, while the corresponding data for the FTY used to develop PECO Exhibit MJT-2 were derived from PECO's capital and operating budgets for the twelve months ending December 31, 2024. The data for the HTY used to develop PECO Exhibit MJT-3 are the data actually recorded in PECO's books of account for the twelve months ended December 31, 2023.

In addition to sponsoring the exhibits described above, I am responsible for responses to certain Pennsylvania Public Utility Commission ("Commission") standard data filing requirements.

7. Q Will you discuss separately PECO Exhibit MJT-1, PECO Exhibit MJT-2, and PECO Exhibit MJT-3?

A. Yes, I will. However, because PECO is basing its proposed rate increase on the adjusted FPFTY data, most of my direct testimony is devoted to explaining PECO Exhibit MJT-1. My testimony regarding PECO Exhibits MJT-2 and MJT-3, which are essentially identical in format to PECO Exhibit MJT-1, will briefly

[2] PECO Exhibits MJT-1, MJT-2, and MJT-3 each contain multiple schedules and each page of the exhibit is numbered on a continuous sequential basis. Specific schedule pages will be cited to using the applicable exhibit pagination. For example, the second page of Schedule B-1, which is the third page of Exhibit MJT-1, will be cited as "Exhibit MJT-1, Schedule B-1, page 3."

address the pro forma adjustments that were made to budget data for the twelve months ending December 31, 2024 and historic actual data for the twelve months ended December 31, 2023, respectively, because the nature of those adjustments is the same or similar to adjustments that I will have already discussed in the context of PECO Exhibit MJT-1. However, I will specifically address any additional adjustments or other differences among those exhibits.

8. Q Please provide an overview of your accounting exhibits.

A. Exhibit MJT-1, which presents PECO's revenue requirement for the FPFTY ending December 31, 2025, is comprised of five sections, as follows:

Section I consists of a summary schedule setting forth PECO's claimed measures of value (i.e., rate base) and the derivation of the Company's requested rate increase.

Section II contains basic accounting data, primarily extracted from the Company's financial records, including a FPFTY-end balance sheet; statements of net operating income and FPFTY revenues; a schedule of expense items by primary account; and a calculation of PECO's tax expenses. Also included are schedules developing PECO's embedded costs of debt and equity, its FPFTY capital structure, and the Company's overall claimed rate of return.

Section III provides a detailed development of the major components of the Company's rate base claim. This section includes summaries of the original cost and accumulated depreciation at FPFTY-end of the various categories of utility plant, including allocated common plant, and calculations of PECO's working

capital, materials and supplies, accumulated deferred income taxes ("ADIT"), regulatory liability for excess ADIT, and customer deposits and advances.

Section IV contains detailed adjustments required to place FPFTY revenues and expenses on a ratemaking basis. These adjustments are summarized on Schedules D-3 to D-17, and, together with certain tax adjustments, are carried forward to Schedule D-1 to derive PECO's pro forma operating income at present and proposed rates.

Section V briefly describes the FTY and HTY data.

Exhibits MJT-2 and MJT-3 are essentially identical in format. Adjustments were made to budgeted data, where necessary, to ensure that the Company's claimed revenue, expenses, and taxes are representative of the levels that the Company expects to experience on a normalized, ongoing basis, and in accordance with the Commission's established ratemaking precedent.

Because PECO is basing its requested rate increase on FPFTY data, Exhibit MJT-1 is key to understanding and evaluating the derivation of the Company's claimed revenue requirement. Exhibit MJT-2 follows the same format as Exhibit MJT-1 but presents information for the FTY ending on December 31, 2024. Exhibit MJT-3 follows the same format as Exhibits MJT-1 and MJT-2, but presents information for the HTY, which ended on December 31, 2023. This information is being furnished in accordance with the Commission's filing requirements and provides a basis for comparing PECO's FPFTY claims to the actual results of historic operations, adjusted for ratemaking purposes, for the HTY.

9. Q How is the balance of your testimony structured?

A. In Section II of my testimony, I present an overview of PECO's FPFTY revenue requirement and explain, in summary fashion, how the claimed measures of value, pro forma present rate revenues, operating expenses, depreciation, and taxes were determined. Section III of my testimony provides a more detailed description of the individual components comprising PECO's requested measures of value for the FPFTY, while Section IV of my testimony discusses the derivation, including appropriate ratemaking adjustments, of PECO's revenue and expense claims for the FPFTY. Section V of my testimony briefly describes the FTY and the HTY data. Section VI of my testimony describes the Company's proposed Storm Reserve Account and explains why adoption of this proposal is appropriate. Section VII of my testimony discusses the one-time surcharge credits that will reduce the Company's revenue requirement in 2025 arising from the COVID-19 Regulatory Asset and the revenue collected in 2021 from Exelon Generation Company, LLC ("Exelon Generation") and Exelon Business Service Company ("EBSC") associated with corrected billings for the use of PECO's fiber network.

II. OVERVIEW OF PECO'S FULLY PROJECTED FUTURE TEST YEAR REVENUE REQUIREMENT

10. Q Please provide an overview of how the Company's FPFTY measures of value were determined.

A. PECO's measures of value, as presented in PECO Exhibit MJT-1, consist of seven principal components: (1) the depreciated original cost of utility plant-in-service (original cost less accumulated depreciation); (2) ADIT; (3) customer

deposits; (4) customer advances for construction; (5) material and supplies; (6) the regulatory liability for excess ADIT; and (7) cash working capital. Each is described briefly below.

Depreciated Original Cost of Utility Plant-in-Service. To determine utility plant-in-service as of the end of the FTY, I began with the closing plant balances actually recorded on the Company's books of account on December 31, 2023, including allocated common plant. To those balances, I added the budgeted capital expenditures for PECO projects that are scheduled to close to plant-in-service (i.e., be placed into service) during the FTY and subtracted the anticipated plant retirements. The same process was used to develop utility plant-in-service balances as of the end of the FPFTY, beginning with the projected balance of plant-in-service on December 31, 2024, adding capital expenditures projected to be closed to plant-in-service by the end of the FPFTY, and subtracting anticipated retirements. The Company's claim for accumulated depreciation was determined in a similar fashion, starting with the accumulated depreciation on December 31, 2023 assigned to each plant account, and bringing those data forward to reflect additional depreciation accruals, plant retirements, and cost of removal net of salvage for the period through December 31, 2024. Accumulated depreciation on December 31, 2025 was then deducted from the projected balance of utility plant as of that date to derive the Company's claimed FPFTY year-end net utility plant of $9.5 billion.

ADIT. The credit balance of ADIT includes the liability for deferred Federal income taxes, net of an offset (debit) for the ADIT assets related to Federal

income tax paid by the Company in advance of recognizing the associated tax determinants for financial reporting purposes, which consist principally of contributions-in-aid-of-construction ("CIAC") recognized as income for income tax purposes.

Customer Deposits, Customer Advances for Construction, and Material and Supplies. The claimed levels of customer deposits and customer advances for construction (both are deducted in determining the measures of value) and material and supplies (which are added) are based on thirteen-month historic averages for the period ended December 31, 2023, consistent with Commission precedent.

Regulatory Liability for Excess ADIT. Due to the reduction in the Federal corporate tax rate that became effective on January 1, 2018, pursuant to the Tax Cuts and Jobs Act ("TCJA"), there is "excess" ADIT. Excess ADIT represents taxes that were deferred prior to January 1, 2018 at the then-applicable 35% tax rate but will be paid to the Federal government, after January 1, 2018 at the current 21% tax rate. The excess ADIT is to be returned to customers over periods that correspond to the periods over which the ADIT would have been paid to the government if the Federal corporate tax rate had not been reduced. To reflect that obligation, the Company has transferred its excess ADIT from the Company's ADIT account to a new regulatory liability account. In addition, on July 8, 2022, Governor Tom Wolf signed Act 53 of 2022 into law. Act 53 incrementally changes the annual rate of Pennsylvania state tax on corporate net income ("CNI") from 9.99% to 4.99% over a period of nine years. Prior to Act

53 taking effect, the CNI tax rate was 9.99%. Act 53 initially lowered the CNI tax rate to 8.99% beginning on January 1, 2023. The CNI tax rate will be lowered each January 1 until the CNI tax rate reaches 4.99% by January 1, 2031. As a result, the Company made a reclassification of ADIT to excess ADIT at the end of 2022. It is important to note that this reclassification was based on the CNI tax rate of 4.99% in 2031. The impact of the CNI tax rate reduction in 2023 was addressed in the Company's 2022 base rate case proceeding at Docket No. R-2022-3031113, where a 9-year amortization for the associated excess ADIT was adopted as part of the approved settlement in that proceeding.[3] The additional impact of CNI tax rate reductions beyond 2023 were passed to customers through the Company's State Tax Adjustment Clause. The sum of the Company's ADIT account and its regulatory liability for excess ADIT on December 31, 2025 is deducted from the Company's measures of value.

Cash Working Capital. Cash working capital was calculated using a lead-lag study and includes elements that are consistent with past practice and Commission precedent.

The components of the measures of value described above are shown in PECO Exhibit MJT-1 on Schedule A-1 at lines 1 to 12 and are discussed in more detail in Section III of my testimony.

[3] *See Pa. P.U.C. v. PECO Energy Co. – Gas Div.*, Docket No. R-2022-3031113 (Order entered October 27, 2022).

11. Q How were the revenues at present rates derived?

A. Revenues at present rates were developed by adjusting the budgeted revenues for PECO's electric operations for the FPFTY to: (1) remove revenues related to portions of the Company's business that are not subject to the jurisdiction of the Commission; (2) remove revenues billed under the surcharge (i.e., non-base rate revenue) that recovers the cost of implementing the Company's energy efficiency and conservation programs pursuant to Act 129; (3) annualize revenues related to changes in the number of customers to reflect year-end levels as of the end of the FPFTY; (4) normalize revenues to reflect 365.25 days; and (5) reflect various pro forma revenue adjustments, which are summarized on Schedule D-5 of PECO Exhibit MJT-1 and are discussed in more detail later in my testimony.

12. Q How were PECO's claimed operating expenses for the FPFTY determined?

A. The pro forma FPFTY expenses were determined using PECO's budget for the twelve-month period ending December 31, 2025 as a starting point. Budgeted expenses, which were prepared based on business activities and related cost elements such as payroll, employee benefits, and outside contracting costs, were distributed to Federal Energy Regulatory Commission ("FERC") accounts based upon the actual distribution experienced by the Company during the calendar year ended December 31, 2023. The budget data were then annualized or normalized in accordance with established Commission ratemaking practices, and other appropriate adjustments were made, all of which are included in Schedule D of PECO Exhibit MJT-1. The necessary adjustments were made to the appropriate FERC accounts.

13. Q Please describe how the taxes-other-than-income were determined for the FPFTY.

A. Those amounts were determined using budgeted amounts for the FPFTY, with pro forma adjustments to payroll taxes to reflect the impact of the increase to FPFTY salaries and wages ("S&W") and other adjustments to reflect known and measurable changes, as shown on Schedule D-16 of PECO Exhibit MJT-1.

14. Q Please describe the calculation of depreciation expense for the FPFTY.

A. The development of annual depreciation for electric and common plant is set forth on Schedule D-17 of PECO Exhibit MJT-1. Each of pages 84 through 87 have columns numbered 1 through 5. Each of pages 88 through 91 have columns numbered 6 through 11. Each of pages 92 through 95 have columns numbered 12 through 17. Columns 1 through 5 show the annual depreciation for electric distribution, transmission, and common plant. Column 6 shows the allocation factors used to allocate annual depreciation to the Electric Division. The allocation factor is 100% for electric distribution plant. For common plant, the allocation factor is 76.93%, which is the portion of common plant allocated to the Electric Division. Columns 7 through 11 show the annual depreciation allocated to the Electric Division. The figures in columns 7 through 11 for common plant reflect the amounts in columns 1 through 6 multiplied by the allocation factor of 76.93%. Column 12 is designed to allocate utility costs between Commission jurisdictional service and non-Commission jurisdictional service. Accordingly, the amounts shown in columns 13 through 17 represent the amounts properly allocated in their entirety to Commission-jurisdictional service for the Electric

Division. For all of the columns, the total for FERC Account 403 Depreciation Expense is shown on line 89 and the total for FERC Account 404 Amortization of Limited-Term Plant is shown on line 130.

The annual depreciation expense budgeted by the Company for electric plant and total-Company common plant is $387.8 million, which is the sum of the amounts shown in column 1, lines 89 and 130. This amount is the annual depreciation developed by Company witness Caroline Fulginiti (PECO Statement No. 4) based on utility plant that will be in service on December 31, 2024 (as shown in Schedule D-17, column 3) and utility plant additions that will be in service on December 31, 2025 (as shown in Schedule D-17, column 2). As Ms. Fulginiti explains, the budgeted annual depreciation amounts for both plant-in-service on December 31, 2024 and for additions during the twelve months ending December 31, 2025 were calculated using depreciation rates that reflect the service life parameters developed in the Company's 2018 service life study. The annual depreciation for plant additions made during the twelve-month period ending December 31, 2025 is based on their expected actual in-service dates and, therefore, reflects less than twelve months of depreciation for that plant. Accordingly, Schedule D-17, column 4, adjusts the amounts in column 1 to annualize the annual depreciation on plant additions made during the twelve-month period ending December 31, 2025. Depreciation expense does not include Asset Retirement Obligations.

The resulting pro forma FPFTY depreciation expense of $407.6 million related to electric plant and common plant is shown in column 5. The resulting pro forma

FPFTY depreciation expense for electric distribution and common plant allocable to the Electric Division's Commission-jurisdictional service is $336.3 million, as shown in column 17. That amount is the sum of $284.0 million shown on line 89 and $52.3 million shown on line 130.

15. Q How were income taxes calculated?

A. Income taxes were calculated using procedures consistent with Commission practice. Federal income tax expense was calculated at the 21% Federal corporate tax rate that became effective on January 1, 2018, pursuant to the TCJA.

The interest expense deduction was synchronized with the Company's measures of value and claimed weighted average cost of long-term debt. The normalization method was used to reflect the tax-book timing differences associated with the use of accelerated methods of tax depreciation to the extent permitted by the Commission and legal precedent. Tax expense was reduced to reflect the amortization of the unamortized investment tax credits ("ITCs"). Tax expense was also reduced to reflect the flow-back of excess ADIT that results from the TCJA's reduction of the Federal corporate tax rate and Pennsylvania CNI tax rate reductions. The income tax claimed for the FPFTY at present rate and proposed rate revenue levels is shown on PECO Exhibit MJT-1, Schedule D-18.

16. Q Please describe how the pro forma revenue increase and revenues at proposed rates were established.

A. Schedule A-1 of PECO Exhibit MJT-1 shows the calculation of PECO's claimed revenue requirement and its requested revenue increase. Column 2, lines 1 to 14, summarize the pro forma measures of value.

Column 2, line 17, shows the Company's electric distribution base rate revenue at present rates. Column 3, line 17, shows the increase over revenues at present rates needed to recover the Company's FPFTY revenue requirement, which is $463.6 million. However, the Company's proposed revenue increase does not include the effects of one-time credits totaling for $64.3 million related to fiber network revenues and the Company's COVID-19 Regulatory Asset, which the Company is proposing to credit to customers in 2025 through reconcilable surcharges. With these two one-time credits, the net increase of revenue at present rates for the FPFTY is $399.3 million.

Lines 22 to 44 of column 2 set forth the calculation of the increase above present rate revenue required to provide the Company the opportunity to earn the overall rate of return of 7.98% calculated on Schedule B-7 and supported by Company witness Moul (PECO Statement No. 5).The resulting required increase in net operating income on line 40 was increased by the Gross Revenue Conversion Factor ("GRCF"), shown on line 42, to provide for Late Payment Charge ("LPC") revenue, uncollectible accounts expenses, gross receipts taxes, regulatory fees and income taxes on the increased revenues requested. The revenue increase shown on line 44 of column 2 is the difference between present rate revenue and

revenues at proposed rates. The increase in unadjusted present rate revenue of approximately $463.6 million is shown on line 44 of column 2 and line 17 of column 3. Column 3, lines 17 through 29, also contain the calculation of the revenue and expenses related to the proposed revenue increase.

Measures of value, revenues, and expenses at proposed rates are shown in column 4, with the resulting overall rate of return of 7.98% shown on line 31 of column 4.

17. Q What is the overall required increase in annual revenues for the Company's jurisdictional distribution operations for the FPFTY?

A. As shown on line 44 of PECO Exhibit MJT-1, Schedule A-1, the proposed increase in annual operating revenues is approximately $463.6 million. As I explained previously, PECO is also proposing a one-time credit of $64 million, resulting in a net electric rate increase of $399 million in 2025.

18. Q What is contained in Schedule B?

A. Schedule B consists of a balance sheet for the total Company on December 31, 2025 reflecting the Company's budget for the twelve months ending December 31, 2025 (Schedule B-1); a statement of Pennsylvania jurisdictional net operating income for the twelve months ending December 31, 2025 (Schedule B-2); a statement of Pennsylvania jurisdictional operating revenue for the twelve months ending December 31, 2025 (Schedule B-3); a statement of Pennsylvania jurisdictional operating and maintenance expense for the twelve months ending December 31, 2025 (Schedule B-4); a detailed breakdown of Pennsylvania jurisdictional taxes other than income for the twelve months ending December 31,

2025 (Schedule B-5); PECO's projected composite cost of long-term debt on December 31, 2025 (Schedule B-6); and the calculation of PECO's claimed overall rate of return for the FPFTY (Schedule B-7). Schedules B-6 and B-7 reflect information derived from the exhibits sponsored by Company witness Moul.

III. MEASURES OF VALUE

A. Summary of Measures of Value

19. Q Please describe Schedule C-1 of PECO Exhibit MJT-1.

A. Schedule C-1, page 17, summarizes the measures of value for the FPFTY for the Company's total Electric Division and its Pennsylvania jurisdictional operations. Column 1 identifies the schedule where each of the measures of value elements is derived, and columns 2 to 4 show the Company's total Electric Division, non-Pennsylvania, and Pennsylvania jurisdictional amounts, respectively. The Company's claimed measures of value for the FPFTY, as shown in column 4, on line 12, is approximately $8.9 billion.

B. Plant-In-Service

20. Q Please describe Schedule C-2 of PECO Exhibit MJT-1.

A. Schedule C-2 contains six pages and presents the Company's claimed FPFTY utility plant-in-service.

21. Q What is shown on Schedule C-2, page 18?

A. Schedule C-2, page 18, is a summary of estimated year-end plant-in-service balances for the FPFTY by functional plant category. Column 2 shows the total-Company electric plant-in-service balance, and column 3 reflects the removal of transmission-related plant. Column 4 reflects the Company's estimated electric distribution plant-in-service at the end of the FPFTY of $11.2 billion (line 47), which is shown on PECO Exhibit MJT-1, Schedule A-1, at column 4, line 2.

22. Q How was total utility plant-in-service for electric distribution operations of $11.2 billion, shown on Schedule C-2, page 18, column 4, line 47, determined?

A. The amount of $13.5 billion shown on Schedule C-2, page 18, column 2, line 47 represents the estimated plant-in-service balance on December 31, 2025 for the Company's Electric Division, including distribution and transmission plant, and is based on utility plant-in-service on December 31, 2023, including distribution and transmission, plus budgeted capital expenditures estimated to be closed to plant-in-service during the FTY and FPFTY, less the estimated retirements in the FTY and FPFTY.

Page 18, column 3 sets forth the adjustments needed to remove intangible plant assigned to transmission, transmission plant included in the transmission accounts, and the portion of general plant allocated to transmission operations. The calculation of the intangible plant and general plant allocated to transmission is described in connection with pages 21 to 23 of Schedule C-2. Column 4

reflects the Company's estimated electric distribution plant-in-service at the end of the FPFTY.

23. Q What is shown on page 19 of Schedule C-2?

A. Page 19 sets forth the Company's estimated additions to be closed to plant-in-service during the FPFTY. These data were developed based on the FTY and FPFTY capital budgets. The total-Company additions of $1.2 billion are shown on line 34, column 1.

24. Q What is shown on Schedule C-2, page 20?

A. Page 20 of Schedule C-2 presents the estimated plant retirements for the FPFTY, based on the average of actual retirements for the period of January 1, 2021 through December 31, 2023.

25. Q What is contained on pages 21 to 23 of Schedule C-2?

A. Pages 21 to 23 detail the adjustments necessary to remove all transmission-related intangible, general, and transmission plant recorded in transmission accounts under FERC jurisdiction from the account balances, as shown in column 5. As shown in column 4, 90.98% of intangible (FERC Account 303) and 87.63% of general plant was allocated to the distribution function. The allocation factors are based on S&W actually recorded in PECO's transmission accounts as a percentage of its total actual S&W in 2023. Most of the intangible plant recorded in FERC account 303 was directly assigned to the transmission and distribution functions, with the balance being allocated using the same S&W factor discussed above.

C. Accumulated Depreciation

26. Q What is the purpose of Schedule C-3 of PECO Exhibit MJT-1?

A. This schedule, consisting of five pages, presents the provision for accumulated depreciation on December 31, 2025 by FERC account, as developed by Company witness Fulginiti, and adjustments related to transmission plant and cost of removal net of salvage, as explained more fully below. PECO's accumulated depreciation of approximately $2.3 billion is summarized on page 24 of Schedule C-3 and then carried forward to line 3 of Schedule A-1.

27. Q Please describe page 24 of Schedule C-3.

A. This page shows the accumulated depreciation balance for the FPFTY by account category, including the accumulated depreciation balance for total electric operations, as shown in column 2, and the adjustments, as shown in column 3, to remove the transmission-related accumulated depreciation, in order to derive the Pennsylvania jurisdictional pro forma accumulated depreciation, as shown in column 4.

28. Q What is contained on pages 25 to 27 of Schedule C-3?

A. Pages 25 to 27 show the accumulated depreciation balance by FERC account at the end of the FPFTY, including the accumulated depreciation balance for total electric operations, as shown in column 1, and the adjustments, as shown in column 6, to remove the transmission-related accumulated depreciation, in order to derive the Pennsylvania jurisdictional pro forma accumulated depreciation shown in column 5. To determine the accumulated depreciation balance at the

end of FPFTY, the Company started with the accumulated depreciation balance on December 31, 2023 and added depreciation expense, less retirements and cost of removal net of salvage, for the FTY and FPFTY. Page 28 of Schedule C-3 shows the cost of removal net of salvage included in the FPFTY accumulated depreciation calculations.

As shown in column 4, 94.11% of accumulated depreciation for intangible (FERC account 303) and 87.63% of accumulated general plant was allocated to the distribution function. The allocation factors were developed in the same manner as the allocation factors I described in connection with Schedule C-2 (i.e., S&W actually recorded in PECO's transmission accounts as a percentage of its total actual S&W in 2023). Consistent with Schedule C-2, most of the intangible plant recorded in FERC account 303 was directly assigned to the transmission and distribution functions, with the balance being allocated using the same S&W factor discussed above. Schedule C-3, page 28 shows the cost of removal net of salvage included in the FPFTY accumulated depreciation calculations, based on the average of actual cost of removal net of salvage for the period of January 1, 2021 through December 31, 2023.

D. Cash Working Capital

29. Q What is set forth on Schedule C-4, page 29, of PECO Exhibit MJT-1?

A. This is a summary of the Cash Working Capital ("CWC") calculations, which are detailed on pages 30 to 37 of this schedule. The total of $214.8 million shown on

line 33 is included in PECO's claimed measures of value as shown on PECO Exhibit MJT-1, Schedule A-1, columns 2 and 4, line 7.

30. Q Please describe page 29 of Schedule C-4.

A. Page 29 summarizes the derivation of PECO's revenue collection lag and overall operating expense payment lag. The revenue lag of 51.95 days is shown on line 3. The expense lag days for each of the components of operating and maintenance expenses appear on lines 6 to 12. Line 15 shows the lag associated with payments to electric generation suppliers ("EGSs") for the purchase of receivables ("POR") from EGSs pursuant to the Company's Commission-approved POR program. The composite operating and maintenance expense and POR payment lag of 34.36 days is shown on line 19. The net lag of 17.59 days (51.95 - 34.36) shown on line 21 is multiplied by the average daily operating expense balance on line 25 to arrive at the base CWC amount of $146.5 million for operating expenses shown on line 27. The average daily operating expense balance of $8.3 million on line 25 was determined by dividing the total pro forma annual operating expenses, excluding uncollectible accounts expense, of $3.0 billion on line 17, column 2, by the number of days in a year, 365. The other components of CWC are shown on lines 29 to 31 and will be described in connection with my discussion of related supporting schedules.

31. Q Please describe the revenue lag calculation shown on Schedule C-4, page 30.

A. The total revenue lag days of 51.95 days is shown on line 29 of page 30 and consists of three parts. First, the average of the month-end accounts receivable balances for the thirteen months ended December 31, 2022 (shown in column 2

on line 21) was divided into the annual revenue billed during the twelve months ended December 31, 2022, (column 3 on line 21) to calculate the accounts receivable turnover rate of 10.21 (column 4, line 21). A turnover rate of 10.21 is equivalent to 35.74 revenue lag days (365 days divided by 10.21 accounts receivable turnover rate), as shown in column 5 on line 21. This is referred to as the collection lag or the payment portion of the revenue lag. The payment portion of the revenue lag is added to: (1) the 1-day lag between the meter reading date and the day that bills are recorded as revenue and accounts receivable by the Company; and (2) the 15.21-day period from the mid-point of the service period until the meter reading date, to calculate the total revenue lag of 51.95 days, as shown on line 29.

32. Q How was the mid-point of the service period calculated?

A. The mid-point of the service period is equal to the days in an average month (365 days divided by 12, or 30.42 days) divided by 2, or 15.21 days.

33. Q Please describe page 31 of Schedule C-4.

A. Schedule C-4, page 31, shows the calculation of the expense lags used in the CWC calculation. Lines 1 to 5 reflect the payroll expense lag. The payroll amounts for the FPFTY are developed on Schedule D-6. The lag periods for the payment of union and non-union payroll are combined because all employees are paid on the same schedule. The lag days reflect PECO's 2024 payment cycles, the last full year for which the payment cycles are known. Lines 7 to 15 show the lag in the payment of pension costs during the FPFTY. The lag period is calculated using a mid-point of July 1 and the payment dates shown in column 2.

This results in an average payment lead of 167 days, which was applied to the pro forma pension expense derived from Schedule D-9, page 74, line 13 and shown on Schedule C-4, page 29, line 7.

34. Q How did you develop the lag days associated with the purchased energy costs shown on line 14 of Schedule C-4, page 37?

A. Effective January 1, 2011, PECO started to purchase power for its default service customers through a Supply Master Agreement. To calculate its CWC requirements, the Company determined, on a monthly basis for the FPFTY, the number of days between the mid-point of the applicable service month and the payment date, which is estimated to be the first business day after the 19th calendar day of the following month. This procedure yields a composite expense lag of 35.71 days as shown on Schedule C-4, page 37, line 14.

35. Q Does the Company plan to purchase 100% of its energy requirements from contract suppliers?

A. No, it does not. Based on the Commission's Final Order in the Company's default service proceeding (Docket No. P-2020-3019290), the Company purchases 1.0% of the energy requirements of its residential default service customers on the spot market and will continue to do so through May 31, 2025. On February 2, 2024, PECO filed a Petition for Commission approval of its default service program for the period from June 1, 2025 through May 31, 2029 and proposed to continue procuring the same percentage residential default service load directly from the spot market.

36. Q Have you calculated a separate expense lag for spot market purchases?

A. Yes. The spot market purchases will be paid weekly, on Friday, for purchases made through the week ended the previous Tuesday. This results in a payment lag of 12.5 days, consisting of 3.5 days from the mid-point to the end of the seven-day service period, and nine days for the period between the end of the service period and the payment date. Since the payments will be made by wire transfer, the total lag days will be 12.5 as calculated on page 37, lines 16 to 24.

37. Q Please address the transmission service charges paid to the PJM Interconnection LLC ("PJM") for transmission service provided by PJM.

A. PJM transmission service charges are paid on the same schedule as the spot market purchases. Consequently, the total lag days for PJM transmission service charges are also 12.5 days.

38. Q How was the expense lag of 37.88 days for POR payments determined?

A. PECO pays electric generation suppliers ("EGSs") 20 days after the billing date for commercial and industrial accounts and 25 days after the billing date for residential accounts. The weighted average payment lag for all accounts is 21.67 days as shown on page 37, line 31. Bill processing takes one day (page 37, line 33), and there is an average of 15.21 days from the mid-point of a service period to the meter reading date (page 37, line 35). The total payment lag, therefore, is 37.88 days (page 37, line 37).

39. Q Please describe how you determined the payment lag associated with other operating and maintenance expenses.

A. The average payment lag for all remaining expenses, as set forth on lines 22 to 27 of Schedule C-4, page 31, was derived from data for the four months shown in detail on Schedule C-4, page 32. More specifically, the Company obtained a listing of all cash disbursements during each of the four months displayed in a format that shows the payee, the date of service or the invoice receipt date, the amount of the disbursement, the date the payment cleared the bank, the account to which the disbursement was charged and certain other data. Each month contains thousands of cash disbursements.

40. Q How did you utilize the data?

A. I used the data in the column showing the number of days it took each disbursement to clear the bank from the invoice receipt date or service date to calculate the dollar days (the amount of the disbursement times the number of days the payment took to clear the bank) and sorted the disbursements by amount. I then eliminated disbursements that should not be included in a CWC calculation or that are included elsewhere in the CWC calculation.

41. Q What disbursements did you eliminate from the balances used on page 32 of Schedule C-4?

A. First, I eliminated all disbursements related to capital charges because they are not part of the Company's claimed operating expenses. Second, I eliminated all disbursements under $1,000 since those amounts, while significant in number,

would not have a meaningful impact on the overall lag-day calculation. Third, I removed all commodity purchases since those are reflected in separate CWC calculations, as I previously described, and are recovered through a separate surcharge. Fourth, I removed all amounts charged to non-expense accounts and any charitable contributions. This process was completed for each of the four months shown on page 32, lines 1 to 11. The total cash disbursements for all four months of $91.7 million, as shown in column 2, on line 14, of page 32 of Schedule C-4, and the related dollar-days of $3.7 billion, shown in column 3, were used to calculate the payment lag for general expenses of 40.07 days shown in column 4. The 40.07 lag days for Other Disbursements were then brought forward to Schedule C-4, page 29, line 12.

42. Q Describe what is shown on Schedule C-4, page 33.

A. This page shows the calculation of the net payment lag days for the tax expense components of PECO's CWC allowance. The first two columns, which are not numbered, identify the type of tax and show the applicable payment schedule for each tax. The payment dates are shown in column 1. The payment lead or (lag) from the mid-point of the year is shown in column 3. The pro forma amount of the payment for each tax is shown in column 4. For example, the pro forma Federal income tax amount, based on the Company's proposed revenue level, is $113.5 million, as shown in column 4, line 1 through 4. The required amounts are shown by payment date for each tax in column 6. The weighted lead (lag) amount for each payment for each tax is calculated in column 7. The weighted lead (lag) days are netted against the revenue lag days shown on page 34, column 4. The

net payment lag shown on page 34, column 5, is used to calculate the average daily amount for working capital shown on page 34, column 7. The net total of the amounts in column 7 is shown on Schedule C-4, page 29, column 2, line 30.

43. Q Please describe the calculation of the interest expense lag shown on page 35 and included on page 29 of Schedule C-4.

A. This calculation measures the lag associated with the semi-annual payment of interest on outstanding debt. The pro forma interest expense is the amount resulting from the synchronized interest calculation using the pro forma measures of value and the weighted cost of debt included in PECO's requested rate of return. The daily interest expense amount, calculated on line 6, is multiplied by the net payment lag of 39.30 days for a reduction to the working capital allowance of $20.4 million, as shown on line 10 and on page 29 at line 31.

44. Q Please explain how the average prepayments of $8.6 million shown on Schedule C-4, page 29, line 29, were determined.

A. Page 36 of Schedule C-4 shows the calculation of the average prepaid expenses included in the CWC. The Company reviewed its prepaid accounts and selected only those prepaid expenses that were related, in whole or in part, to its electric delivery operations. The resulting prepaid accounts are shown in columns 2 to 17. Where items related entirely to the electric operations, such as the PUC Assessment in column 6, the total and average monthly amount were charged entirely to electric distribution, as shown on line 17 in columns 2 to 10. Where the account related to both electric and gas operations, the total and average were distributed using an appropriate allocation factor that eliminates both gas-related

expenses and non-jurisdictional expenses, as shown on line 17 in columns 11 to 14. Finally, where the prepaid expense is related to electric distribution and gas operations, a factor was used to isolate only electric distribution operations, as shown on line 17 in columns 15 to 17. The thirteen-month average for prepaid expenses for the electric distribution operations is $8.6 million as shown on line 25 of Schedule C-4, page 36 and on Schedule C-4, page 29, line 29.

45. Q What is the total amount of CWC included in the claimed measures of value?

A. That amount is the $214.8 million shown on Schedule C-4, page 29, column 2, line 33, and on Schedule A-1, page 1, column 2, line 7.

E. ADIT

46. Q What is the purpose of Schedule C-6?

A. Schedule C-6, page 39 shows the December 31, 2025 balance of ADIT that is deducted in determining the measures of value. The ADIT shown in column 6, line 22 of $596.6 million reflects the Federal income tax that must be deferred in compliance with the normalization provisions pertaining to the use of accelerated tax depreciation for Federal income tax purposes on test year plant balances and other tax-book timing differences that have been normalized. The accelerated tax depreciation used in the determination of taxable income for Federal and state income tax expense calculations is reflected on Schedule D-18. As discussed in the direct testimony of Company witness Marissa Humphrey (PECO Statement No. 2), the ADIT includes the deferred tax asset associated with the new

corporate alternative minimum tax ("CAMT") implemented by the IRA beginning in 2023.

47. Q Have you made an adjustment for the Federal income tax on CIAC?

A. It was not necessary to make a separate adjustment for CIAC. CIAC is treated as a capital contribution for ratemaking purposes but is treated as taxable income for Federal income tax purposes. PECO pays the Federal income tax due on CIAC in the year the CIAC is received and included in taxable income. The associated tax payment is recorded as a debit to the ADIT account, which normally carries a credit balance. Consequently, the net effect of the calculation of ADIT properly reflects the tax-book timing difference related to taxes paid on CIAC.

48. Q What is the amount of ADIT used in the measures of value?

A. The amount for electric distribution operations is $596.6 million, as shown in column 6, line 22 of Schedule C-6, page 39 and on line 8 of Schedule A-1, in columns 2 and 4.

F. Customer Deposits

49. Q Please explain how you determined the amount of customer deposits on Schedule C-7 that was deducted from the claimed measures of value on Schedule A-1.

A. The customer deposits shown on Schedule C-7, page 40, in column 4 (lines 1-13) reflect the month-end balances for the thirteen months ended December 2023. The Company maintains a joint customer deposit account because many of its customers use both its electric and natural gas services. Total Company customer

deposits were allocated between electric and gas operations based on electric and gas customer class revenues. Schedule C-7 shows the customer deposits related solely to the Company's electric distribution operations.

50. Q Where are these amounts of customer deposits and interest shown?

A. The total of customer deposits for all classes of electric distribution customers is a deduction to measures of value of $57.3 million, as shown on Schedule C-7, page 40, line 17, and on Schedule A-1, line 9 of columns 2 and 4. The calculated interest expense related to these customer deposits of $3.6 million, as shown in Schedule D-12, is included in the Company's operating expenses as shown on PECO Exhibit MJT-1, Schedule D-3, page 51, column 15, line 94.

G. Common Plant

51. Q What is shown on Schedule C-8?

A. This schedule shows the common plant, net of accumulated depreciation, included in the measure of value on Schedule A-1.

H. Customer Advances for Construction

52. Q What is contained on Schedule C-9?

A. This schedule shows the average monthly balance of customer advances for construction of $2.9 million on line 19, which is deducted in calculating the measures of value on Schedule A-1, line 10, columns 2 and 4.

53. Q How were the monthly balances determined?

A. The Company was able to identify the specific amounts attributable to its electric distribution operations based on a review of its accounting records.

I. Materials and Supplies

54. Q Please describe Schedule C-11.

A. Schedule C-11 shows the derivation of PECO's claim for materials and supplies and undistributed stores expense. The materials and supplies balances in column 2 were specifically identified as electric distribution-related amounts and, therefore, 100% of those amounts is shown on line 22 in column 2. The undistributed stores expense shown in column 3 reflects amounts attributable to PECO's total utility operations and, therefore, the electric distribution allocation factor of 67.41% was applied to determine the thirteen-month average of monthly balances, as shown on line 22, in column 3. The claimed amount of $30.4 million reflected in column 4 is based on the thirteen-month average for the period ended December 31, 2023 and is shown on line 12, columns 2 and 4, of the measures of value on Schedule A-1.

J. ADIT – Regulatory Liability

55. Q What is shown on Schedule C-12?

A. Schedule C-12 shows the calculation of excess ADIT that has been removed from the ADIT account and recorded as a regulatory liability.

56. Q What is the Company's claimed measures of value in this proceeding?

A. PECO's claimed measures of value, or rate base, equals $8.9 billion, as shown on line 14 of Schedule A-1.

IV. REVENUES AND EXPENSES

57. Q What is shown on Schedule D-1 of PECO Exhibit MJT-1?

A. Schedule D-1 is a summary income statement that depicts PECO's claimed electric revenues, expenses and taxes at present and proposed rate levels. The derivation of most of the individual line items will be discussed in connection with the remaining schedules in Section D. Schedule D-1 also shows the proposed revenue increase of $463.6 million on line 13 in column 3.

58. Q What is the indicated net operating income at proposed rates?

A. As shown on Schedule D-1, column 4, line 30 and on Schedule A-1, column 4, line 24, that amount is $806.5 million.

59. Q Please describe Schedule D-2.

A. Schedule D-2 shows the derivation of the various line items on Schedule D-1, column 2. Schedule D-2 begins with the Company's budgeted revenues and expenses for its Pennsylvania jurisdictional electric operations for the FPFTY, in column 2, and then annualizes and/or normalizes those figures through adjustments summarized in column 3. The pro forma data in column 4 are summarized and brought forward to Schedule D-1 and used in the determination of the required revenue increase. The various revenue adjustments in column 3 are summarized on Schedule D-3 and listed by adjustment on Schedule D-5, and the expense adjustments are summarized on Schedule D-3 and described in more detail on the separate adjustment schedules beginning with Schedule D-6 and continuing through Schedule D-17.

60. Q Please describe Schedule D-3.

A. Schedule D-3 summarizes the various adjustments that were made to the budgeted revenue and expense data to derive the pro forma amounts at present rates that appear in column 4 of Schedule D-2 and are included in the adjusted amounts that are carried forward to column 2 of Schedule D-2. The FPFTY budgeted amounts are shown in column 1 and the revenue adjustment totals are shown in columns 2 to 8. The various expense adjustments are reflected in columns 9 to 20. Each of the pro forma adjustments will be described in connection with the specific schedule supporting the adjustment. The pro forma adjusted amounts for the FPFTY are shown in column 22.

61. Q Please describe Schedule D-4.

A. Schedule D-4 contains four pages and presents a summary of the pro forma operating expenses shown on Schedule D-3 by FERC account.

A. Revenue Adjustments

62. Q Please describe Schedule D-5.

A. Schedule D-5 presents a summary of the separate pro forma adjustments to revenue for the FPFTY. Each of these adjustments will be described in detail in connection with the separate calculation of the adjustment shown on Schedules D-5A to D-5G.

63. Q How did you calculate the revenue adjustment shown on Schedule D-5A?

A. This adjustment annualizes distribution revenues for the projected number of customers at the end of the FPFTY. As shown on lines 1 to 5, for all customer

classifications this calculation determines the pro forma test year distribution revenues, excluding reconcilable surcharges, at present rates for the FPFTY. The average distribution revenues on line 5 were divided by the average number of customers for the year included in the budget for the twelve months ending on December 31, 2025 on line 7 to determine the average distribution revenue per customer on line 9. The average distribution revenue, or margin, per customer for the FPFTY on line 9 was then multiplied by the difference between: (1) the average number of customers (line 7); and (2) the number of customers at the end of the FPFTY (line 11), which difference is shown on line 13, yielding additional revenue of approximately $2.9 million for the residential, residential heating and small commercial and industrial customer classes, as shown on line 15 by customer classification. This pro forma adjustment is then reflected on Schedule D-5, page 60, column 2 by customer classification.

64. Q Please describe the adjustment calculated on Schedule D-5B.

A. This adjustment annualizes the cost of the discounts provided to customers enrolled in PECO's Customer Assistance Program ("CAP") in the form of a bill credit, reflecting the number of CAP customers at the end of the FPFTY. As shown in line 8 of columns 2 and 3, the average CAP discount per CAP customer is determined by dividing the total budgeted CAP discount on line 1 by the average number of CAP customers shown on line 7. The average CAP discount per CAP customer is then multiplied by the difference between the FPFTY year-end CAP customers on line 10 and the average number of CAP customers shown on line 7. This yields a total decrease in the CAP discount of $2.0 million, which

is offset by an uncollectible accounts factor of 5.5% and CWC factor of 5% as shown on line 15. These offset factors are discussed in more detail by Company witness Jacqueline F. Golden (PECO Statement No. 10). Thus, the total net decrease of $1.8 million is shown on line 17, which is brought forward to column 3 in Schedule D-5.

65. Q Please describe the adjustment on Schedule D-5C.

A. This adjustment shows the reductions in revenue that the Company expects to experience related to the reductions in load that the Company must achieve in order to comply with the energy efficiency and conservation provisions of Act 129 of 2008. The Company's implementation of its approved programs has yielded considerable benefits for customers by helping them to save energy and, in some cases, to reduce demand. The energy savings, however, have caused and will continue to cause substantial reductions in the Company's distribution revenues. The Company is proposing to recognize those distribution revenue reductions by reducing budgeted FPFTY distribution revenues by the average of the projected incremental revenue losses to be experienced in 2026 over revenue losses included in the 2025 budget.

66. Q What is the total amount of the pro forma revenue adjustment the Company is proposing?

A. As shown on Schedule D-5C, page 63, column 5, line 27, the Company is proposing a pro forma revenue adjustment to its FPFTY budgeted revenue of $3.8 million, which will allow the Company to recover its lost revenue for 2026 through the rates established in this proceeding.

67. Q In your opinion, is it reasonable for PECO to request that these energy savings be recognized in the determination of its revenue requirement?

A. Yes, for primarily two reasons. First, Act 129 specifically contemplates that revenue reductions attributable to the mandated energy efficiency programs be taken into account in establishing base rates. My adjustments are designed to achieve that end by setting rates based on sales levels that reflect the incremental lost revenues related to mandatory Act 129 usage reductions in 2026. Second, it would be unfair to require PECO to implement these programs, or be subjected to possible penalties for non-compliance with legislatively imposed energy-reduction goals, and then deny it rate recovery of the lost revenues, particularly given the tremendous benefits that inure to customers. This adjustment aligns the customer and Company interests in promoting energy-conservation, providing significant savings to the customers and permitting PECO to recover lost revenues during the same period that the customers are receiving the benefits of reduced bills from the legislatively-mandated and Commission-approved programs.

68. Q Please describe the adjustment shown on Schedule D-5D.

A. This adjustment removes the budgeted revenues associated with the recovery of costs associated with developing and implementing PECO's energy-efficiency and conservation programs. Act 129 allows such costs to be recovered through a separate Section 1307 reconcilable adjustment clause. PECO will continue to utilize its Energy Efficiency and Conservation Plan surcharge mechanism for the recovery of these costs in the future. Therefore, the associated surcharge revenues have been removed from base rate revenue.

69. Q Please describe the adjustment shown on Schedule D-5F.

A. This adjustment normalizes revenue the Company budgeted for the FPFTY by increasing variable distribution service charge revenue to reflect an additional 0.25 days. The Company's budgeted revenue for the FPFTY is based on 365 days, reflecting the 28 calendar days in February 2025. This adjustment normalizes revenue to reflect the average number of days in the month of February over a four-year cycle that includes one leap year. The customer charge revenue does not change irrespective of the number of days in a year and, therefore, is not adjusted in this schedule. Additionally, the classes have variable distribution service charges that apply to kilowatt hours of usage and, therefore, are sensitive to the number of days of usage in the test year. Line 1 of Schedule D-5F shows the non-customer and non-reconcilable surcharge distribution revenue for the classes for February 2025. Lines 2 and 4 show the number of days in February 2025 and the normalized number of days in that month over a four-year cycle. The difference is shown in line 5. The adjustment necessary to normalize revenues for 0.25 days is shown, by class on line 7.

B. Operating Expense Adjustments

70. Q Does the Company budget its operating expenses by FERC account?

A. No, as I mentioned previously, it does not. Rather, the Company budgets its operating expenses by cost element or business activity, such as payroll, employee benefits, rent, etc.

71. Q How were the FPFTY data restated by FERC account for purposes of preparing the Company's supporting data in this case?

A. The amounts recorded in FERC accounts as of the end of the HTY were analyzed to develop a chart showing charges for each cost element within each FERC account in the transmission function, the distribution function, the Administration and General ("A&G") transmission function, the A&G distribution function and the A&G general function. After this process was completed, I then distributed the forecasted FPFTY charges by cost elements in those cost categories to the corresponding FERC accounts based upon the ratios experienced in the HTY. For example, I determined how much of the S&W expensed in the HTY was charged to each FERC account in the HTY distribution function and then distributed the FPFTY forecasted distribution S&W to distribution FERC accounts based on those ratios. This process was used for each cost category to transform the FPFTY expense forecast by cost element to a FERC-based forecast. This FERC-based forecast is brought forward to Schedule B-4.

72. Q Why was it necessary to transform the FPFTY cost-category forecast to a FERC-account based forecast?

A. It was done for two reasons. First, the Company's annual reports to the Commission are presented on a FERC-account basis and, therefore, having the FPFTY forecast presented in the same format facilitates a comparison of the FPFTY forecast data to prior years' experience. Second, it was necessary to have the FPFTY data available by FERC account for use by Company witness Tamara J. Jamison (PECO Statement No. 6) in the cost-of-service study.

73. Q In your opinion, does this process result in a fair presentation of the Company's FPFTY forecast expenses by FERC account?

A. Yes, it does.

74. Q Were each of the pro forma adjustments reflected on Schedule D-4 also assigned to the appropriate FERC accounts?

A. Yes, they were.

75. Q Are the various pro forma expense adjustments presented on Schedule D-4 shown by the type of expense and also by the FERC account distribution?

A. Yes, they are. The expense categories are identified in the headers of the columns on Schedule D-4, and each adjustment is described in connection with a separate schedule showing its derivation. These adjustments are shown by FERC expense category on Schedule D-4 and also on the Section D summary schedules.

76. Q Please describe Schedule D-6.

A. Schedule D-6 consists of four pages and shows the calculation of the FPFTY annualization adjustments for S&W. Pages 68 and 69 show the calculation of the pro forma adjustments for overall S&W. Pages 70 and 71 contain the forecasted data for the FPFTY summarized by FERC account categories showing a total to be expensed of $167.9 million on page 71, column 1, line 72. Column 2 on page 70 shows the annualization adjustment of $5.7 million distributed to the FERC expense categories, while column 3 provides the pro forma amounts for S&W expense, which totals $173.7 million, as shown on line 72. The adjustment of $5.7 million is reflected on Schedule D-4, column 3.

77. Q How was the annualization adjustment derived?

A. The calculation is shown on Schedule D-6, pages 68 and 69. The adjustment annualizes budgeted S&W expense to reflect the number of employees at the end of the FPFTY and certain wage increases to become effective during the FPFTY or shortly after the FPFTY. More specifically, I have annualized: (1) the 2.5% wage increase for union employees forecasted to be effective on January 1, 2025 (lines 7 to 9 in column 2); (2) the 3.0% wage increase for non-union employees forecasted to be effective on March 1, 2025 (lines 7 to 9 in column 3); (3) the projected 2.5% wage increase for union employees to be effective on January 1, 2026 (lines 13 to 15 in column 2); and (4) the projected 3.0% wage increase for non-union employees to be effective on March 1, 2026 (lines 13 to 15 in column 3).

78. Q Please explain the adjustment shown on lines 6 to 10 of Schedule D-6, page 69.

A. This adjustment normalizes a cash payment to union employees made in connection with the ratification of current union contracts in March 2021. The portion of the payment that was expensed ($1.303 million) was split between electric distribution, electric transmission and gas operations, and the amount allocated to electric distribution operations $1.0 million was divided by six to reflect the six-year term of the contract. The resulting amount of $168,000 shown in column 2, line 10, was added to the pro forma adjustment for S&W.

79. Q Please explain the calculations shown on Schedule D-6, page 69, column 2, lines 15-19.

A. These calculations annualize an increase in the number of employees during the FPFTY. As shown in line 15, column 2, the projected number of Company employees at the FPFTY year-end is 2,373. The average number of employees during the FPFTY is projected to be 2,366, which is the figure that the Company used to develop the S&W in its budget which is shown in line 16, column 2. The detailed calculation of the average number of employees included in the budgeted expense level is shown on Schedule D-8, page 73, in lines 2 to 15. The increase in employees shown on line 17 was then multiplied by average annual S&W per employee shown in Schedule D-6, page 69, line 18, to determine the total annualization adjustment to S&W of $470,000 due to the increase in number of employees, as shown on Schedule D-6, page 69, line 19.

80. Q What is the total pro forma adjustment for S&W expense for the FPFTY?

A. The total amount is $5.7 million, which is an increase of 3.4% from the Company's S&W budget for the FPFTY, as shown on Schedule D-6, page 69, lines 23 and 25.

81. Q Please describe Schedule D-7 of PECO Exhibit MJT-1.

A. Schedule D-7 shows the adjustment to normalize rate case expense. The Company expended approximately $9,000 on this filing during the twelve months ended December 31, 2023 (line 4) and has budgeted an additional $2.391 million (line 9) during the twelve months ending December 31, 2024. This total, $2.4

million (line 11), is normalized over a period of two years as shown on line 13, column 2, which results in a total estimated normalized annual cost for this case of approximately $1.2 million, as shown on line 17, column 2.

82. Q Please describe Schedule D-8 of PECO Exhibit MJT-1.

A. The bottom half of Schedule D-8 annualizes the non-pension employee benefits expense to reflect the full year's level of costs associated with the number of employees during the FPFTY. The annualization, reflecting an increase of $64,000 in non-pension benefit expense, was derived by using the increase in the number of employees, on line 22, and the budgeted average non-pension benefit expense per employee of approximately $10,000 on line 21.

83. Q Please explain how you calculated the change in number of employees to a year-end level on Schedule D-8.

A. Line 15 shows the twelve-month average of employees that is reflected in the Company's budget. I compared the twelve-month average to the number of employees reflected in the budget to be employed on December 31, 2025. The difference is shown on line 16. Because the average and year-end employee numbers reflect rounding to obtain the levels of full-time equivalent employees, the difference between those figures does not exactly match the figure on line 16.

84. Q What is contained in PECO Exhibit MJT-1 Schedule D-9?

A. Schedule D-9 shows the calculation of the Company's claim for pension expense, which is based on a five-year average of actual and projected contributions to its pension plan. The portion of the pension cost assigned to electric distribution

operating expense in the FPFTY is $3.2 million, as shown on line 13. Accordingly, an adjustment of $3.3 million has been made to the Company's FPFTY budget amount, as shown on line 15, and the adjustment amount was brought forward to Schedule D-3, column 12, line 112.

85. Q What is presented on Schedule D-10 of PECO Exhibit MJT-1?

A. Schedule D-10 calculates an adjustment to the Company's budgeted uncollectible accounts expenses. Lines 1 to 4 calculate net uncollectible accounts charged off, excluding CAP Pre-Program Arrearage ("PPA") write-offs, as a percentage of total tariff revenue, based on an average of annual data for the period of January 1, 2021 through December 31, 2023. That percentage was used to adjust the amount of uncollectible accounts expense in the budget to conform to the method historically used by the Commission for this expense. The resulting 0.9708% shown on line 4, column 7, of Schedule D-10 is applied to the pro forma revenues at present rates for the FPFTY to calculate the general pro forma uncollectible accounts expense of $38.3 million shown in column 9 on line 14. A three-year average of PPA associated with the CAP program, which are not included in other accounts, was added to the general uncollectible accounts expense. The PPA average is $9.3 million, as shown on line 20 in column 9.The total pro forma amount for uncollectible account expenses at present rates for the FPFTY is $47.6 million, which is a net increase of $9.5 million, as shown on line 26 and brought forward to page 51 of Schedule D-3 (column 13, line 93). In addition, the 0.9708% write-off rate is used in determining the level of uncollectible accounts expense at proposed rates, as shown in column 3 on line 19 of Schedule D-1.

86. Q Please describe Schedule D-11.

A. Schedule D-11 calculates an adjustment for incremental costs incurred by the Company related to its request for Federal funding from the U.S. Department of Energy's Grid Resilience and Innovation Partnerships program, as part of the Infrastructure Investment and Jobs Act ("IIJA"). The Company was selected to negotiate an award of up to $100 million under this program to support modernization of its grid. Schedule D-11, column 2, line 1 shows the incremental expense incurred for its electric distribution operations in years 2022 and 2023 of $411,000, which is amortized over two years to arrive at the annual amortization of $205,000 as shown on Schedule D-11, page 76, column 2, line 3. The Company also estimated an incremental expense of $653,000 for the FPFTY in its budget, but due to the uncertainty of costs in and beyond 2024, an adjustment to remove the $653,000 is shown on line 4 to arrive at the total pro forma adjustment of ($448,000) as shown on Schedule D-11, page 76, column 2, line 5. Given the uncertainty of the exact amount of incremental costs in and beyond 2024, PECO will seek full recovery of all prudent incremental costs actually incurred in and beyond 2024 in the Company's subsequent base rate proceedings in accordance with the Commission's regulatory asset authorization for all utilities pursuing Federal funding under the IIJA in its July 13, 2023 Opinion and Order entered at Docket No. P-2022-3032929.

87. Q Please describe the pro forma adjustment on Schedule D-12.

A. The adjustment shown on Schedule D-12 captures the interest expense that the Company must pay on customer deposits. Since the average balance of customer

deposits is a reduction to measures of value, the interest expense is included as a pro forma expense for the FPFTY. The interest for residential customer deposits was calculated using an annual rate of interest of 8.0% and a monthly rate of 0.667%. An annual rate of 5.1% (a monthly rate of 0.425%) was used for commercial and industrial customers. The total pro forma expense of $3.6 million is shown on Schedule D-12, line 33 and brought forward to Schedule D-3, page 51.

88. Q Please describe the pro forma adjustment on Schedule D-13.

A. This adjustment shown on line 13 reflects an increase of $14.2 million to FPFTY budget expenses for storm damage restoration expenses. PECO is proposing, for ratemaking purposes, to normalize storm damage expense based on a rolling 60-month historical storm damage expense up to the end of first quarter in 2024. A rolling 60-month average includes a period long enough to reflect appropriate levels of expense associated with normal storm events, including major storms and extraordinary storms.

89. Q Please describe the adjustments for miscellaneous items shown on Schedule D-14.

A. Schedule D-14 includes two adjustments to refund small over-collection balances to customers. First, column 2, line 6 shows the refund amount of $62,000 associated with the final reconciliation of the Tax Accounting Repair Credit and column 2, line 12 reflects a $23,000 refund associated with the final reconciliation of the Company's Federal Tax Adjustment Credit. Both adjustments are described by Company witness McDevitt in Statement No. 8. Schedule D-14 also

includes additional annual funding of $1.0 million as shown in column 2, line 17, to offer electric vehicle ("EV") charger rebates as part of the Company's proposal to extend the term of its existing EV charging pilot by five years through 2029. This program is discussed in greater detail by Company witness Steven DeMott (PECO Statement No. 9).

C. Taxes – Other Than Income Taxes

90. Q Please describe Schedule D-16 of PECO Exhibit MJT-1.

A. Schedule D-16 contains three pages. Page 81 is a summary showing the budgeted amounts for the FPFTY (column 2) for the total Company, adjustments to eliminate the non-Pennsylvania jurisdictional amounts (column 3), the total pro forma adjustments (column 5), and the pro forma expenses claimed in this case (column 6). The calculations for payroll-related changes are made on Schedule D-16, page 82, while the changes in the gross receipts tax ("GRT") are shown on page 83. The increase in payroll taxes, shown on page 82, line 5, was calculated using the ratio of tax expense to payroll expense in the FPFTY forecast applied to the payroll tax expense for the FPFTY, which is an increase of $0.4 million. This amount is then reflected on page 81 in column 5, line 5. The adjustment to decrease GRT by $5.6 million shown on line 8, in column 5 of page 81, is calculated on page 83. Total pro forma taxes other than income are $192.3 million, as shown on Schedule D-16, page 81, line 10, column 6.

91. Q Did you make an adjustment to recognize the additional GRT attributable to the revenue increase allowed by the Commission in this proceeding?

A. Yes. As will be described in connection with PECO Exhibit MJT-1, Schedule D-19, the incremental GRT is recovered through the application of the Gross Revenue Conversion Factor ("GRCF") used to determine the amount of revenue required to provide the increase in net income claimed by PECO.

D. Depreciation Expense

92. Q What is shown on PECO Exhibit MJT-1, Schedule D-17, pages 84 to 95?

A. I described Schedule D-17 in detail earlier in my testimony. As I explained, Schedule D-17 shows the development of the Company's claims for annual depreciation for electric distribution and common plant. Schedule D-17 starts with the annual depreciation for electric distribution and common plant developed by Company witness Fulginiti and presented in PECO Exhibit CF-3. The adjustments set forth on Schedule D-17, in addition to allocating a portion of common plant to the Electric Division, annualize depreciation expense related FPFTY additions to reflect a full year's depreciation for that plant. PECO's total depreciation expense annualization adjustment for the Company's electric distribution business is $17.3 million, which is the sum of the amounts shown on Schedule D-17, column 16, lines 89 and 130.

E. Income Taxes

93. Q Please describe the income tax calculation shown on PECO Exhibit MJT-1, Schedule D-18, pages 96 and 97.

A. This schedule calculates the pro forma income tax expense for the FPFTY at present and proposed rates, as set forth in columns 1 and 3, respectively. Line 1 shows the revenue at present rates, the revenue increase (with the related late payment charge increase) and revenue at proposed rates. Line 2 shows the total operating expenses at present rates, changes related to the revenue increase and at the proposed rates from Schedule D-1. Line 3 shows the operating income before income taxes. Synchronized interest expense is calculated on lines 5 to 7 using the total measures of value for the FPFTY on line 4 and the weighted cost of debt recommended by Company witness Moul on line 6. The resulting interest expense on line 7 is used to reduce the taxable income to the amount shown on line 8.

In compliance with Commission practice, the difference between accelerated tax depreciation (line 10) and pro forma book depreciation (line 11) is used to adjust the state taxable income as shown on line 8 to reflect the fact that the effects of accelerated depreciation are flowed through for state income tax purposes. In addition, there are adjustments to other tax-book differences and flow-through amounts as shown on lines 13 to 18. These adjustments result in the net reduction of state taxable income from line 8 to line 20. The statutory state income tax rate of 7.99% was used to determine the pro forma current state income tax expense shown on line 26. Federal income tax expense is calculated on lines 28 to 41 with

a Federal corporate income tax rate of 21%. Line 43 shows the total current State and Federal income tax expense before the amount for deferred income taxes is calculated. Lines 45 to 54 reflect the Federal and state deferred income taxes.

The total income tax expense before other adjustments is shown on line 56 at present and proposed rates in columns 1 and 3 respectively, including the flow-back of excess ADIT resulting from the lower Federal corporate income tax rate under the TCJA and from the reduction of the Pennsylvania CNI tax rate, as discussed above. The other adjustments include the amortization of ITC for electric distribution plant, including the portion of common plant allocated to electric distribution, as shown on line 59.

94. Q Please explain the nature and calculation of the ITC amortization.

A. The ITC reflects tax credits used by the Company in years prior to 1987, the amortization of which will not have been completed by the end of the FPFTY. While the availability of the ITC ended in 1987, the credit has been amortized over the useful lives of the assets that generated it. The amortization for the FPFTY ending December 31, 2025 reduces income tax expense at both present and proposed rates, shown on Schedule D-18, page 97.

95. Q Please explain the adjustment to flow-back excess ADIT.

A. As I previously explained, the TCJA reduced the Federal corporate income tax rate from 35% to 21% effective January 1, 2018, and the Company's ADIT balances as of December 31, 2017 reflect taxes that were deferred at the higher corporate income tax rates in effect prior to January 1, 2018. PECO has recorded

excess ADIT in a regulatory liability account. For ADIT that relates to tax-book timing differences associated with utility plant subject to the normalization requirements of the Internal Revenue Code, PECO is required to flow back the difference between its ADIT balance and what its ADIT balance would have been if the deferrals had been made at the current 21% corporate tax rate (excess ADIT) over the remaining lives used in its books of account for the property that gave rise to the reserve for deferred taxes. The Company used the Average Rate Adjustment Method, as defined by applicable IRS regulations, for this purpose. Shorter flow-back periods are permissible for property that is not subject to normalization requirements. Schedule D-18, page 97, line 49, reflects the annual amount of the regulatory liability to be flowed back. As I explained earlier, for the excess ADIT resulting from changes to the Pennsylvania CNI tax rate, the Company made a reclassification of ADIT to excess ADIT at the end of 2022 based on the CNI tax rate of 4.99% in year 2031. The Company has been utilizing its State Tax Adjustment Clause to pass the impact to customers since the beginning of 2023. Schedule D-18, page 97, line 50 reflects the annual amount of the regulatory liability to be flowed back to customers over a period of 9 years.

96. Q Has PECO included a consolidated income tax adjustment ("CTA") in its calculation of Federal income tax expense?

A. No, it has not, because such an adjustment is no longer authorized under Section 1301.1(a), which was added to the Public Utility Code by Act 40 of 2016. Act 40 became law on June 12, 2016 and was effective sixty days later (August 11, 2016) to "all cases where the final order is entered after the effective date of [Section

1301.1]." Consequently, Section 1301.1 applies to this case. Section 1301.1(a) specifies how the Commission is to compute income tax expense for ratemaking purposes. Section 1301.1(b) states how any incremental internally-generated funds produced by the application of Section 1301.1(a) should be used by an affected utility pending the December 31, 2025 "sunset" of Section 1301.1(b).

97. Q What does Section 1301.1 direct the Commission to do in calculating income tax expenses for ratemaking purposes?

A. In summary, Section 1301.1(a) provides that current and deferred income taxes of a Pennsylvania utility are to be calculated for ratemaking purposes based only on the income, deductions and credits of the utility itself. Therefore, the Commission may not take into account income, deductions (including taxable losses) or credits of the utility's parent or affiliated companies with which it joins in filing a consolidated Federal income tax return. This is generally referred to as a stand-alone computation of income tax expense because it reflects income tax expense of the utility standing alone and without regard to taxable income, deductions or credits of other companies in the same consolidated group.

98. Q How does Section 1301.1(a) change prior Commission practice?

A. Section 1301.1(a) terminates the practice of making a CTA when calculating a utility's Federal income taxes for ratemaking purposes in Pennsylvania. As directed by prior decisions of Pennsylvania appellate courts, the Commission, until Act 40 became effective, was required to calculate CTAs employing the "Modified Effective Tax Rate Method." Under the Modified Effective Tax Rate Method, the consolidated tax savings generated by the non-regulated companies

of a corporate group were allocated to the regulated and non-regulated members of the group having positive taxable incomes. CTAs, therefore, captured a portion of the tax benefits of deductions – including taxable losses – of unregulated affiliates of public utilities and gave those benefits to the utilities' customers (as lower income tax expense than the utilities would have on a stand-alone basis) even though the utilities' customers did not pay the expenses that gave rise to those tax benefits. With the enactment of Act 40, Pennsylvania joins the majority of other jurisdictions, including the Federal Energy Regulatory Commission, that do not make CTAs for ratemaking purposes.

99. Q What does Section 1301.1(b) provide?

A. Section 1301.1(b) states as follows:

> If a differential accrues to a public utility resulting from applying the ratemaking methods employed by the commission prior to the effective date of subsection (a) for ratemaking purposes, the differential shall be used as follows:
>
> (1) fifty percent to support reliability or infrastructure related to the rate-base eligible capital investment as determined by the commission; and
>
> (2) fifty percent for general corporate purposes.
>
> Section 1301.1(b) will no longer apply after December 31, 2025.

100. Q Have you calculated the "differential" in income taxes referenced in Section 1301.1(b)?

A. Yes, Schedule D-18, page 98 sets forth the computation of a CTA using the Modified Effective Tax Rate Method and data for tax years 2018 through 2022, which are the most recent five years for which tax returns have been filed.

Column 7, line 28 shows the "differential" corresponding to the CTA calculated in the manner I described above.

101. Q How does PECO propose to invest 50% of the differential in rate base-eligible reliability projects or other infrastructure improvements?

A. The differential will be used to target reliability projects and other infrastructure improvements described by Company witness Nicole L. LeVine (PECO Statement No. 1).

102. Q What is PECO's total income tax expense claim in this proceeding?

A. As shown on Schedule D-18, page 97, line 61, column 2, pro forma income tax benefit at present rates equals $18.2 million. The increment for income tax expense associated with the proposed revenue increase is shown in column 3, in the amount of $118.0 million, and the total pro forma income tax expense at proposed rates of $99.8 million is shown in column 4.

103. Q Please explain Schedule D-19.

A. This schedule shows the calculation of the GRCF used on Schedule A-1 to determine the revenues required to achieve the overall rate of return requested by PECO. The conversion factor captures the additional late payment revenue, uncollectible accounts expense, GRT, regulatory fees, and Federal and state income taxes attributable to the additional revenues resulting from the proposed rate increase.

V. FUTURE TEST YEAR AND HISTORIC TEST YEAR

104. Q Please describe the process used to prepare the pro forma FTY and HTY presentations in PECO Exhibit MJT-2 and PECO Exhibit MJT-3, respectively.

A. The basic process was the same as described in connection with PECO Exhibit MJT-1, except I used budgeted data for the FTY and actual recorded data for the HTY as the starting point for each exhibit. As with the FPFTY, I reviewed the budgeted data for the FTY and recorded data for the HTY and, where appropriate, made pro forma adjustments. In addition, I used data from PECO Exhibit MJT-1 as the basis for several of the pro forma amounts used in PECO Exhibits MJT-2 and MJT-3.

105. Q What assumptions did you make to determine what pro forma adjustments would be necessary for the FTY and HTY?

A. I included pro forma adjustments that reflected the annualization and normalization of FTY and HTY elements and adjustments for future events that have impacted the FPFTY. For example, I have annualized S&W expense for increases and adjusted for the year-end number of employees, as I did in the FPFTY. The pro forma adjustments for the FTY and HTY are numbered consistently with the adjustments for the FPFTY. For example, the adjustment for S&W is on Schedule D-6 in all three test years to facilitate reference between the FPFTY, the FTY and the HTY. Where there is no adjustment required for the FTY or the HTY, the correlation simply shows that further adjustment is not applicable.

106. Q Referring now to PECO Exhibit MJT-2, for the FTY, what is contained on Schedule A-1?

A. Schedule A-1 shows a summary of the measures of value on lines 1 to 14, operating revenues and expenses and calculated rates of return at present and proposed rates on lines 16 to 31, and the revenue increase required on lines 33 to 44.

107. Q What is contained on Schedules B-1 to B-5?

A. These schedules contain budgeted financial data for the FTY, with the separation of the total electric operating income statement into non-Pennsylvania and Pennsylvania jurisdictional amounts.

108. Q Please describe Schedules B-6 and B-7.

A. These two schedules contain the FTY pro forma capital structure and rate of return developed by Company witness Moul. As shown on lines 1 to 6 of Schedule B-7, the Company is using its expected capital structure at the end of the FTY and cost rates as shown on Schedule B-7.

109. Q Please describe Schedule C-1.

A. Schedule C-1 lists the measures of value components. The measures of value total for the FTY is $7.9 billion, as shown on column 4, line 14.

110. Q What is contained in Schedule C-2?

A. Schedule C-2 consists of six pages and shows the utility plant-in-service balances on December 31, 2021 for the Company's electric distribution operations, as well as the additions, retirements and adjustments for the FTY. Pages 21 to 23 contain

the summary of pro forma plant-in-service balances by plant grouping and reflects adjustment to plant. Page 18 shows the plant-in-service by FERC accounts. Pages 19 and 20 show the additions to plant and retirements from plant during the FTY. The total pro forma plant-in-service at the end of the FTY is $10.2 billion and is shown on Schedule C-2, page 18, column 4, line 47.

111. Q Please describe Schedule C-3.

A. Schedule C-3 contains five pages and shows the accumulated depreciation on December 31, 2021. These pages show the pro forma balances by FERC account developed using the same procedures employed for the FPFTY. The accumulated depreciation at the end of the FTY is $2.2 billion, as shown on page 24, column 4, line 47.

112. Q What is contained in Schedule C-4?

A. Schedule C-4 consists of nine pages that show the calculation of the CWC allowance for the FTY of $222.3 million on page 29, line 33. The information for average prepayments on line 29 is the same as utilized in PECO Exhibit MJT-1 because the FPFTY claim is based on the thirteen-month average for the period ended December 31, 2023. In addition to the prepayments, the methodology used to calculate the lag periods for revenue, payroll, pension expense, commodity purchases and other disbursements utilized in PECO Exhibit MJT-1 were also used in the FTY calculation.

Page 29 provides a summary of the calculations for each of the elements of the CWC for the FTY. The expenses in column 2 and those included in the

determination of the lead-lag amounts for taxes, interest and preferred dividends are the pro forma amounts for the FTY, while the prepayment amount is the thirteen-month average of month-end balances through December 31, 2023. The resulting $222.3 million of CWC shown on line 33 is brought forward to Schedule A-1 in the calculation of the measures of value.

113. Q Please describe pages 30 to 37 of Schedule C-4.

A. These pages show the calculations of various leads and lags and working capital requirements for the FTY following the same procedures used for the FPFTY as described in connection with PECO Exhibit MJT-1, Schedule C-4. While the amounts for the FTY expenses vary from those in the FPFTY, the procedures followed to determine the lead/lag periods applied to those expense levels are the same as those described in connection with the corresponding PECO Exhibit MJT-1 schedules.

114. Q Please describe the calculations on Schedule C-6.

A. These calculations show the ADIT for the FTY. The procedures followed to determine FTY ADIT were the same as those utilized for the ADIT calculation at the end of the FPFTY except that year-end December 31, 2024 balances were used. The resulting ADIT of $595.7 million for the total of electric distribution utility plant and the electric distribution portion of the common plant for the FTY is shown on line 15. As shown on Schedule C-12, line 9, $281.3 million of excess ADIT has been removed from the ADIT balance and recorded as a regulatory liability.

115. Q Please describe the data presented on Schedules C-7, C-9, and C-11.

A. The data on these three schedules are the same as the data presented and described in connection with the comparable schedules in PECO Exhibit MJT-1, since the same thirteen-month period was used.

116. Q Please describe the calculation of common plant shown on Schedule C-8.

A. This schedule shows the common plant, net of accumulated depreciation, included in the measures of value on Schedule A-1 for the FTY.

117. Q What is presented on Schedule D-1?

A. Schedule D-1 shows the net operating income at present rates for the FTY, the pro forma revenue deficiency, and the pro forma required revenue level.

118. Q Please describe Schedule D-2.

A. Schedule D-2 shows revenues and expenses budgeted for the FTY, pro forma adjustments, and the pro forma revenue and expense amounts at present rates. This schedule summarizes the adjustments that are detailed on Schedules D-3 and D-5 and explained in connection with other supporting schedules to be described later in my testimony.

119. Q Please describe Schedule D-3.

A. Schedule D-3 contains nine pages which present a summary of each of the pro forma adjustments made to revenues and operating expenses, including depreciation and taxes-other-than-income taxes. Each of the adjustments will be described in connection with the specific schedule containing the calculation of the adjustment.

120. Q What is contained in Schedule D-4?

A. This schedule contains four pages and shows the budgeted and pro forma adjustment amounts for the FTY by revenue category and by FERC account for expenses.

121. Q Please describe Schedule D-5.

A. Schedule D-5 shows the pro forma adjustments to the FTY budgeted revenues. Each of the listed adjustments is discussed in connection with Schedules D-5A to D-5G. All of these adjustments were prepared using the same methodology as described in connection with PECO Exhibit MJT-1.

122. Q Please describe the adjustment shown on Schedule D-5A.

A. The adjustment shown on Schedule D-5A annualizes revenues for customer growth during the FTY. The process utilized is the same as described in connection with the same adjustment for the FPFTY on PECO Exhibit MJT-1, Schedule D-5A.

123. Q What is the adjustment shown on Schedule D-5B?

A. The adjustment shown on Schedule D-5B annualizes CAP discounts for the FTY. The process utilized is the same as described in connection with the corresponding adjustment for the FPFTY shown on Schedule D-5B of PECO Exhibit MJT-1.

124. Q Please describe the adjustment shown on Schedule D-5C.

A. This adjustment reflects the average of the revenue losses associated with the load reductions mandated by Act 129. The Company is using the same calculation for the FTY that was used for the corresponding adjustment for the FPFTY.

125. Q Please describe the adjustment shown on Schedule D-5D.

A. Similar to Schedule D-5D of PECO Exhibit MJT-1, this schedule removes the Energy Efficiency and Conservation program costs and related cost recovery that was included in the Company's FTY budget. The Company will continue to use the approved surcharge mechanism to recover its Energy Efficiency and Conservation program related costs and, as consequence, the costs and revenues related to the surcharge are properly removed from base rate revenue and base rate revenue requirement.

126. Q Please describe the adjustment shown on Schedule D-5F.

A. This schedule shows the development of a normalized level of distribution revenue based on the average number of days per year in a four-year cycle.

127. Q Please describe Schedule D-6.

A. Schedule D-6 annualizes S&W for the FTY. Pages 70 and 71 show the budgeted amounts in column 1 and the pro forma adjustment in column 2 by FERC expense category. Pages 68 and 69 show the calculation of the annualization adjustments of S&W, the normalization of the union contract ratification payment and a one-time labor cost increase, which follow the same procedures described in connection with the FPFTY using the data from FTY for the wage increases.

128. Q What is contained on Schedule D-7?

A. Schedule D-7 normalizes rate case expenses using the same recorded and estimated amounts used in the FPFTY calculation shown on PECO Exhibit MJT-1, Schedule D-7.

129. Q Please describe the adjustment shown on Schedule D-8.

A. This adjustment, which annualizes non-pension benefits related to the change in number of employees during the FTY, was calculated using the same procedures used for the comparable adjustment for the FPFTY and described in connection with PECO Exhibit MJT-1, Schedule D-8.

130. Q Please describe the adjustment shown on Schedule D-9.

A. This adjustment for pension expense and to annualize non-pension benefits follows the same procedures used for the FPFTY and described in connection with PECO Exhibit MJT-1, Schedule D-9.

131. Q Are the adjustments shown on Schedules D-10 to D-15 similar to the adjustments included in PECO Exhibit MJT-1 and described in connection with the schedules presented in that exhibit?

A. Yes, they are.

132. Q Please describe Schedule D-16.

A. Schedule D-16 shows the development of the Company's claim for taxes other than income taxes for the FTY.

133. Q Please describe Schedule D-17.

A. Schedule D-17 presents the pro forma adjustment for depreciation to annualize depreciation expense for plant amounts at the end of the FTY, similar to the pro forma adjustment described in connection with the pro forma adjustment in PECO Exhibit MJT-1.

134. Q Please describe the income tax calculations on Schedule D-18.

A. This schedule shows the calculation of the pro forma income tax expense for the FTY reflecting the revenues, expenses and measures of value included in the pro forma present rate data for the Company and a 21% Federal corporate tax rate. In addition to the tax depreciation amounts, the ITC amortization was calculated, as shown on pages 96 and 97 of Schedule D-18. The flow-back of excess ADIT was reflected in calculating income tax. The total calculated income tax shown on line 61 was used in the calculation of the overall revenue requirement shown on Schedule A-1.

135. Q Referring now to PECO Exhibit MJT-3, for the HTY, what is contained on Schedule A-1?

A. Schedule A-1 shows a summary of the measures of value on lines 1 to 14, operating revenues and expenses and calculated rates of return at present and proposed rates on lines 16-31, and the revenue increase required on lines 33-44.

136. Q What is contained on Schedules B-1 to B-5?

A. These schedules contain recorded financial data for the HTY, with the separation of the total electric operation income into non-Pennsylvania and Pennsylvania jurisdictional amounts.

137. Q Please describe Schedules B-6 and B-7.

A. These two schedules contain the pro forma capital structure and rate of return used for the HTY, which are supported by Company witness Moul. As shown on lines 1 to 6 of Schedule B-7, the Company is using its capital structure at the end of the HTY and cost rates as shown on Schedule B-7.

138. Q Please describe Schedule C-1.

A. Schedule C-1 lists the measures of value components. The measures of value total for the HTY is $6.9 billion, as shown on column 4, line 12.

139. Q What is contained in Schedule C-2?

A. Schedule C-2 consists of six pages and shows the utility plant-in-service balances on December 31, 2023 for the Company's distribution operations, as well as the adjustments for the HTY. Pages 21 to 23 contain the summary of pro forma plant-in-service balances by plant grouping. Page 18 shows the plant-in-service by FERC account. Pages 19 and 20 are left blank intentionally because they reflect schedules that are used for the FTY and FPFTY but are not relevant to the HTY. Finally, adjustments to plant are reflected on pages 21 to 23 of Schedule C-2. The total pro forma plant-in-service at the end of the HTY is $9.3 billion and is shown Schedule C-2, page 18, column 4, line 47.

140. Q Please describe Schedule C-3.

A. Schedule C-3 contains five pages and shows the accumulated depreciation on December 31, 2023. These pages show the pro forma balances by FERC account following the same procedures employed for the FPFTY. The accumulated depreciation at the end of the HTY is $2.1 billion, as shown on page 24, column 4, line 47.

141. Q What is contained in Schedule C-4?

A. Schedule C-4 consists of nine pages that show the calculation of the CWC allowance for the HTY of $219.3 million on page 29, line 33. The information for average prepayments on line 29 is the same as utilized in PECO Exhibit MJT-1 because the FPFTY claim is based on the thirteen-month average for the period ended December 31, 2023. In addition to the prepayments, the methodology used to calculate the lag periods for revenue, payroll, pension expense, commodity purchases, and other disbursements utilized in PECO Exhibit MJT-1 were also used in the FTY calculation.

Page 29 provides a summary of the calculations for each of the elements of the CWC for the HTY. The expenses in column 2 and those included in the determination of the lead-lag amounts for taxes, interest and preferred dividends are the pro forma amounts for the HTY, while the prepayment amount is the thirteen-month average of month-end balances through December 31, 2023. The resulting $219.3 million of CWC shown on line 33 is brought forward to Schedule A-1 in the calculation of the measures of value.

142. Q Please describe what is shown on pages 30 to 37 of Schedule C-4.

A. These pages show the calculations of various leads and lags and working capital requirements for the HTY following the same procedures used for the FPFTY as described in connection with PECO Exhibit MJT-1, Schedule C-4. While the amounts for the HTY expenses vary from those in the FPFTY, the procedures followed to determine the lead/lag periods applied to those expense levels are the same and were described in connection with the corresponding schedules in PECO Exhibit MJT-1.

143. Q Please describe the calculations shown on Schedule C-6.

A. These calculations show the ADIT for the HTY. The procedures followed to determine HTY ADIT were the same as those utilized for the ADIT calculation at the end of the FPFTY, except that year-end December 31, 2023 balances were used. The resulting ADIT of $613.8 million for the total of electric distribution plant and the electric distribution portion of common plant for the HTY is shown on line 6. As shown on Schedule C-12, line 3, $288.3 million of excess ADIT has been removed from the ADIT balance and recorded as a regulatory liability.

144. Q Please describe the data presented on Schedules C-7, C-9, and C-11.

A. The data on these three schedules are the same as the data presented and described in connection with PECO Exhibit MJT-1, because the same thirteen-month period was used.

145. Q Please describe the calculation of common plant shown on Schedule C-8.

A. This schedule shows the common plant, net of accumulated depreciation, included in the measures of value on Schedule A-1 for the FTY.

146. Q What is presented on Schedule D-1?

A. Schedule D-1 shows the net operating income at present rates for the HTY, the pro forma revenue deficiency and the pro forma required revenue level.

147. Q Please describe Schedule D-2.

A. Schedule D-2 shows revenue and expenses for the HTY, pro forma adjustments and the pro forma revenue and expense amounts at present rates. This schedule summarizes the adjustments that are detailed on Schedules D-3 and D-5 and explained in connection with other supporting schedules to be described later in my testimony.

148. Q Please describe Schedule D-3.

A. Schedule D-3 contains nine pages, which provide a summary of each of the pro forma adjustments made to revenues and operating expenses, including depreciation and taxes other than income taxes. Each of the adjustments will be described in connection with the specific schedule containing the calculation of the adjustment.

149. Q What is contained in Schedule D-4?

A. This schedule contains four pages and shows the recorded amounts and pro forma adjustment amounts for the HTY by revenue category and by FERC account for expenses.

150. Q Please describe Schedule D-5.

A. Schedule D-5 shows the pro forma adjustments to the HTY revenues. Each of the listed adjustments is discussed in connection with Schedules D-5A to D-5G. All of these adjustments were prepared using the same methodology described in connection with PECO Exhibit MJT-1, except Schedule D-5G, which is the weather normalization adjustment to distribution revenue recorded in 2023.

151. Q Please describe the adjustment shown on Schedule D-5A.

A. This adjustment on Schedule D-5A annualizes revenues for customer growth during the HTY. The process utilized is the same as that described in connection with the same adjustment for the FPFTY on PECO Exhibit MJT-1, Schedule D-5A.

152. Q What is the adjustment shown on Schedule D-5B?

A. The adjustment shown on Schedule D-5B annualizes CAP discounts for the HTY. The process utilized is the same as described in connection with the corresponding adjustment for the FPFTY shown on PECO Exhibit MJT-1, Schedule D-5B.

153. Q Please describe the adjustment shown on Schedule D-5C.

A. This adjustment reflects the average of the revenue losses associated with the load reductions mandated by Act 129. The Company is using the same calculation for the HTY that was used for the corresponding adjustment for the FPFTY.

154. Q Please describe the adjustment on Schedule D-5D.

A. Similar to the comparable schedule in PECO Exhibit MJT-1, Schedule D-5D removes the Energy Efficiency and Conservation program-related costs and cost recovery that was recorded in the HTY. The Company will continue to use the Commission-approved surcharge mechanism to recover Energy Efficiency and Conservation program related costs.

155. Q Please describe the adjustment on Schedule D-5F.

A. This schedule shows the development of a normalized level of distribution revenue based on average number of days per year in a four-year cycle, which I previously explained.

156. Q Please describe the adjustment shown on Schedule D-5G.

A. Schedule D-5G shows the adjustment to normalize HTY distribution revenue to reflect normal weather for weather sensitive load. This adjustment does not apply to the FTY and the FPFTY because the distribution revenue for both of those years was budgeted on the basis of normal weather.

157. Q Please describe Schedule D-6.

A. Schedule D-6 annualizes S&W for the HTY. Pages 70 and 71 show the budgeted amounts in column 1 and the pro forma adjustment in column 2 by FERC expense category. Pages 68 and 69 show the calculation of the annualization adjustments of S&W, the normalization of the union contract ratification payment and a one-time labor cost increase, which follow the same procedures described in connection with the FPFTY using the data from the HTY for the wage increases.

158. Q What is contained on Schedule D-7?

A. Schedule D-7 normalizes rate case expenses using the same recorded and estimated amounts used in the FPFTY calculation shown on PECO Exhibit MJT-1, Schedule D-7.

159. Q Please describe the adjustments shown on Schedule D-8.

A. This adjustment, which annualizes non-pension benefits related to the change in number of employees during the HTY, was calculated using the same procedures used for the comparable adjustment for the FPFTY and described in connection with PECO Exhibit MJT-1, Schedule D-8.

160. Q Please describe the adjustment on Schedule D-9.

A. This adjustment to pension expense in the HTY follows the same procedures used for the FPFTY, which were described in connection with PECO Exhibit MJT-1, Schedule D-9.

161. Q Are the adjustments on Schedules D-10 to D-15 similar to the adjustments included in PECO Exhibit MJT-1 and described in connection with the schedules presented in that exhibit?

A. Yes, they are.

162. Q Please describe Schedule D-16.

A. Schedule D-16 shows the development of the Company's claim for taxes other than income taxes for the FTY.

163. Q Please describe Schedule D-17.

A. Schedule D-17 presents the pro forma adjustment for depreciation to annualize depreciation expense for plant balances at the end of the HTY, similar to the pro forma adjustments described in connection with the comparable schedules in PECO Exhibits MJT-1 and MJT-2.

164. Q Please describe the income tax calculations on Schedule D-18.

A. This schedule shows the calculation of the pro forma income tax expense for the HTY reflecting the Company revenue, expenses and measures of value included in the pro forma present rate data and a 21% Federal corporate tax rate. In addition to the tax depreciation amount, ITCs were calculated for electric operations, as shown on pages 96 and 97 of Schedule D-18. The flow-back of excess ADIT was reflected in calculating income tax. The total calculated income tax shown on line 61 was used in the calculation of the overall revenue requirement shown on Schedule A-1.

VI. STORM RESERVE ACCOUNT

165. Q What level of storm damage expenses is recovered in PECO's base rates?

A. Consistent with prior Commission practice, the Company normalizes storm damage expense based on a five-year historical average of actual storm damage expense. Its base rates have been designed to recover only a "normal" level of storm damage expense. Stated another way, base rates are not designed to reflect experience that deviates materially from a historically derived baseline of "normal" storm damage expense. As a result, base rates may reflect more than

actual costs in a given year with a lower than "normal" level of storm activity. On the other hand, higher than "normal" levels of storm activities are not reflected in the level of expense recovered in base rates.

166. Q Please describe the Company's request to establish a tracker and deferral account for storm damage expenses.

A. In the last decade, PECO has experienced material variances between the level of storm damage expense recovered through its base rates and the level of those expenses actually incurred due to the increasing volatilities in frequency, severity and duration of weather events that are outside the Company's control. Due to the volatility in weather events from year-to-year, actual storm damage expense can be notably lower or higher than the amounts reflected in PECO's base rates. Therefore, PECO is asking for Commission permission to defer and record any amounts above or below the Company's base rate allowance for storm damage expense to a Storm Reserve Account. Deferral accounting authorization is a fair way to ensure that PECO recovers its actual storm damage expenses – no more or less – and that customers are only paying for actual storm costs.

167. Q What is the difference between the Storm Reserve Account and a rate adjustment clause established under Section 1307 of the Code?

A. Under the Storm Reserve Account proposed by PECO, the differences between the storm expenses included in the Company's rates and its actual storm expenses will be tracked and recorded in deferral accounts. The net balance in the accounts would represent a deferral – either as a regulatory liability or regulatory asset – that would be credited to, or recovered from, customers in a subsequent base rate

case by means of an appropriate amortization. In contrast, a rate adjustment mechanism established under Section 1307 of the Public Utility Code typically involves billing customers a charge calculated to recover a projected annual cost. Annually (or more frequently), the amount billed to customers is reconciled to the utility's actual cost and the difference is either recovered from or refunded to customers through the experience or "E" factor of the formula for the rate adjustment clause. In that way, customer rates are periodically adjusted to reflect changes in actual costs and the reconciliation of prior period over or under-collections.

Under a rate adjustment clause, customer rates are subject to change between base rate cases. Under the deferred accounting mechanism the Company is proposing for storm expenses, variations between projected and actual expenses are to be recorded and deferred, but customer rates will not reflect the net impact of those variations until new rates are authorized in a future base rate case.

168. Q Why is it appropriate for PECO to record the amount of storm damage expenses above or below the amount authorized in rates to the Storm Reserve Account between base rate cases?

A. The Commission regularly authorizes utilities to defer costs for accounting purposes arising from extraordinary and non-recurring events to provide the utility an opportunity to claim those costs for recovery in a future rate proceeding. The Commission has granted petitions to defer storm damage expenses in recognition of the fact that this type of cost of might evade legitimate recovery under typical ratemaking practices because storm damage expenses are not within

the control of a utility and are difficult to project for purposes of prospective recovery in base rates.[4]

169. Q How would the storm reserve accounting work?

A. Each month, the amount of storm damage expense included for recovery in base rates ("base level") will be compared to the Company's actual monthly expense. In this case, the monthly amount for base level set forth in PECO Exhibit MJT-1, Schedule D-13, allocated to each month based on the total monthly retail distribution revenue in this proceeding. Actual storm costs incurred above or below the base level will be credited or debited, as applicable, in the Storm Reserve Account on the Company's books for accounting purposes. In its next base rate case, the Company shall seek rate recognition of the net credit or debit balance in the Storm Reserve Account with interest, which will represent either a regulatory asset or regulatory liability as applicable, amortized over two years as either an increase or decrease, respectively, to storm damage expense. PECO's proposal for interest on any over- or under-recovery will protect customers from any timing deviation of the recovery and actual storm costs.

[4] *See*, *e.g.*, *Pa. P.U.C. v. PPL Elec. Utils. Corp.*, Docket No. R-2012-2290597 (Opinion and Order entered Apr. 23, 2014), pp. 15, 21-22.

170. Q Has the Company reviewed how the fluctuations in storm expense from year to year would have impacted PECO and its customers had the Storm Reserve Account been in place previously?

A. Yes. Table 1 below compares PECO's "rate allowance" for storm damage expense and the actual amount of expense recorded. The rate allowance figures presented in the second column of Table 1 are the Company's claimed amounts of storm damage expense in its initial base rate case filings where new rates became effective on January 1, 2016, January 1, 2019, and January 1, 2022. Because each of those base rate cases were resolved by black box settlement, PECO used its claimed amounts as a representative figure for storm expense embedded in rates to provide a comparison to actual costs.

Significantly, over the eight years (2016-2023) reflected in Table 1, customers would have realized net benefits (actual costs lower than the rate allowance) totaling $15 million if the Storm Reserve Account had been in place during that period. Since the Company's current rates became effective on January 1, 2022, the Company would have recorded a regulatory liability of $39 million.

Table 1

($ millions)

Year	Rate Allowance	Actual Storm Damage Expense	Variance
2016	$ 46	$ 16	$ 30
2017	46	9	37
2018	46	64	(18)
2019	44	36	8
2020	44	115	(71)
2021	44	54	(10)
2022	51	22	29
2023	51	41	10
Total	$ 372	$ 357	$ 15

VII. REVENUE REQUIREMENT EFFECTS OF RATE CREDITS IN 2025

171. Q Please summarize the ratemaking treatment authorized by the Commission for PECO's COVID-19 Regulatory Asset in the Company's 2021 electric base rate case.

A. On May 13, 2020, the Commission issued a Secretarial Letter[5] that recognized the additional costs and other financial impacts that the COVID-19 pandemic imposed on utilities as essential businesses, including the increased costs directly resulting from the service-termination moratorium established by the Emergency Order issued by former PUC Chairman Gladys Brown Dutrieuille on March 13, 2020.[6] The May 2020 Secretarial Letter directed utilities to track incremental COVID-19 related expenses and any government assistance that would offset those expenses and permitted utilities to establish a regulatory asset for bad debt expense attributable to compliance with the Emergency Order.

[5] *COVID-19 Cost Tracking and Creation of Regulatory Asset*, Docket No. M-2020-3019775 (Secretarial Letter issued May 13, 2020) ("May 2020 Secretarial Letter").

[6] *Public Utility Service Termination Moratorium Proclamation of Disaster Emergency-COVID-19*, Docket No. M-2020-3019244 (Emergency Order ratified Mar. 26, 2020) ("Emergency Order").

In its 2021 electric base rate case, PECO calculated its claim for uncollectible expense using a three-year historic average (2018-2020) of net charge-offs as a percentage of billings. The Company also proposed to recover the amount of its COVID-19 Regulatory Asset totaling $48.25 million, amortized over three years. That balance represented the amounts to be booked by the Company for uncollectible expense that was above the amount embedded in PECO's base rates for calendar years 2020 and 2021. In the same base rate case proceeding, the Company proposed the incremental uncollectible expense regulatory asset recovery in that proceeding be used in the subsequent rate case as a deduction to the overall claims in order to avoid any double-charging to customers. Under the settlement approved by the Commission in the 2021 Rate Case Order, the parties agreed that PECO's base rates effective January 1, 2022 reflect a three-year amortization of the Company's COVID-19 Regulatory Asset (i.e., $16.08 million per year), and that the Company would cease recording any incremental COVID-19 related uncollectible accounts expense as of December 31, 2021.

172. Q Why is the Company proposing surcharge credits in 2025 for the $48.2 million deferred balance of the COVID-19 Regulatory Asset amortized in PECO's base rates from January 1, 2022 through December 31, 2024 to customers?

A. As discussed earlier in my testimony, the Company's uncollectible expense claim in this case is based on the average of net charge-offs as a percentage of sales for the period of 2021 to 2023, consistent with the Company's prior practice. The Company is proposing to use the incremental uncollectible expense regulatory

asset recovery authorized in the 2021 Rate Case Order ($48.25 million) to reduce the overall revenue requirement in this case to ensure that the amount embedded in PECO's current rates is not also included in the level of uncollectible expense claimed in proposed rates based on a three-year charge-off average for the period of January 1, 2021 through December 31, 2023. The $48.25 million will be credited to customers in 2025 through the Incremental COVID-19 Uncollectible Surcharge as described by Ms. McDevitt in PECO Statement No. 8.

173. Q Is PECO proposing any other customer rate credits in this case?

A. Yes. In November 2021, during the course of the Commission's Management Audit of the Company's electric operations at Docket No. D-2021-3023906, PECO identified unbilled intercompany charges for leasing a portion of its fiber network to its former affiliate Exelon Generation and EBSC. Subsequently, the Company collected $12,014,797 from Exelon Generation and $1,521,437 from EBSC. PECO booked interest on this amount at 6%, which results in a total balance of approximately $16 million. This amount will be credited to customers in 2025 through the Fiber Affiliate Revenue Surcharge as described by Company witness McDevitt in PECO Statement No. 8.

VIII. CONCLUSION

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

A. Yes, it does.

PECO Exhibit MJT-1:

Principal Accounting Exhibit – Fully Projected Future Test Year ending December 31, 2025

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Present Rates	Revenue Increase	Total
1	**MEASURE OF VALUE**				
□	Utility Plant	C-2	$11,242,906		$11,242,906
□	Accumulated Depreciation	C-3	2,253,728		2,253,728
□	Common Plant - Net of Accum Depr	C-8	555,965		555,965
□	Net Plant in service	L2 - L3 + L4	$9,545,143		$9,545,143
□					
□	Working Capital	C-1	$214,843		$214,843
□	Accum Deferred Income Taxes	C-1	(596,644)		(596,644)
□	Customer Deposits	C-1	(57,291)		(57,291)
10	Customer Advances for Construction	C-1	(2,889)		(2,889)
11	Materials and Supplies	C-1	30,350		30,350
1□	Accum Deferred Income Taxes - Reg Liability	C-1	(277,875)		(277,875)
1□					
1□	TOTAL RATE BASE	SUM L5 to L12	$8,855,637		$8,855,637
1□					
1□	**OPERATING REVENUES AND EXPENSES**				
1□	Base Customer Charges	D-5	$1,788,967	$463,632	$2,252,599
1□	Electric Cost Revenue	D-5	$1,071,200		1,071,200
1□	Other Operating Revenues	D-5	$48,022	1,406	49,427
□0	Total Revenues	SUM L17 to L19	$2,908,189	$465,038	$3,373,227
□1					
□□	Operating Expenses	D-1	$2,533,736	$32,966	$2,566,702
□□					
□□	OIBIT	L20 - L22	$374,453	$432,072	$806,525
□□					
□□	Income Taxes @ Eff Inc Tax Rate	D-18	$18,163		$18,163
□□	Income Taxes @ Statutory Rates	D-18		($118,008)	($118,008)
□□					
□□	NET OPERATING INCOME	SUM L24 to L27	$392,616	$314,064	$706,680
□0					
□1	RATE OF RETURN	L29 / L14	4.43%		7.98%
□□					
□□	**REVENUE INCREASE REQUIRED**				
□□	Rate of Return at Present Rates	L31	4.43%		
□□					
□□	Rate of Return Required	B-7	7.98%		
□□					
□□	Change in ROR	L36 - L34	3.55%		
□□					
□0	Change in Operating Income	L14 * L38	$314,064		
□1					
□□	Gross Revenue Conversion Factor	D-19	1.476		
□□					
□□	Change in Revenues	L40 * L42	$463,632		
□□					
□□	**RETURN ON COMMON EQUITY**				
□□	Common Equity Ratio	B-7	53.40%		
□□	Common Equity Rate Base	L14 * L47	$4,728,910		
□□	NET OPERATING INCOME	L29	$392,616		
□0	Synchronized Interest Expense	D-18	$188,625		
□1	NET OPERATING INCOME - COMMON EQUITY	L49 - L50	$203,991		
□□	RATE OF RETURN ON COMMON EQUITY	L51 / L48	4.31%		

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$20,062,028
3	Construction Work In Progress (107)		659,623
4	Total Utility Plant	L2 + L3	$20,721,651
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		5,007,287
6	Net Utility Plant	L4 - L5	$15,714,364
7			
8	**Other Property and Investments**		
9	Non-Utility Property (121)		$11,249
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,448
11	Invest in Assoc Company (123)		7,725
12	Other Investments (124-129, 175-176)		27,679
13	Total Other Property and Investments	SUM L9 to L12	$45,204
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments (131-136)		$25,000
17	Customer Accounts Receivable (142)		442,289
18	Other Accounts Receivable (143)		35,649
19	Accum. Prov. for Uncollectible (144)		(83,303)
20	Receivables from Assoc. Comp. (146)		
21	Fuel Stock (151)		38,067
22	Plant Materials & Supplies (154)		69,125
23	Prepayments (165)		20,632
24	Accrued Utility Revenues (173)		215,498
25	Miscellaneous Current & Accrued Assets (174)		87,744
26	Total Current and Accrued Assets	SUM L16 to L25	$850,700
27			
28	**Deferred Debits**		
29	Unamortized Debt Expense (181)		$54,014
30	Other Regualtory Assets (182.3)		1,123,689
31	Miscellaneous Deferred Debits (186)		740,795
32	Unamortized Loss on Reacquired Debt (189)		636
33	Accumulated Deferred Income Taxes (190)		(0)
34	Total Deferred Debits	SUM L29 to L33	$1,919,133
35			
36	**TOTAL ASSETS**	L6+L13+L26+L34	$18,529,402

		(1)	(2)
Line No.	Description	Reference	Total - PECO
37	**Proprietary Capital**		
38	Common Stock Issued (201)		$1,423,004
39	Preferred Stock Issued (204)		
40	Other Paid-In Capital (208-211)		3,703,533
41	Capital Stock Expense (214)		(87)
42	Retained Earnings (215, 215.2, 216)		2,419,374
43	Unappropriated Undistributed Subsidiary Earnings (216.1)		
44	Accum Other Comprehensive Income (219)		
45	Total Propriety Capital & Margins	SUM L38 to L44	$7,545,824
46			
47	**Long Term Debt**		
48	Bonds (221)		$6,400,000
49	Advances from Associated Companies (223)		184,419
50	Other Long-Term Debt (224)		
51	Unamortized Premium on LTD (225)		
52	Unamortized Discount on LTD (226)		(21,980)
53	Total Long-Term Debt	SUM L48 to L52	$6,562,439
54			
55	**Other Non-Current Liabilities**		
56	Obligations under Capital Leases (227)		
57	Accum. Prov for Injuries & Damages (228.2)		$35,157
58	Accum. Prov for Pensions & Benefits (228.3)		303,426
59	Accum. Miscellaneous Operating Prov (228.4)		18,397
60	Asset Retirement Obligation (230)		26,348
61	Total Other Non-Current Liabilities	SUM L56 to L60	$383,328
62			
63	**Current and Accrued Liabilities**		
64	Notes Payable (231)		$150,436
65	Accounts Payable (232)		648,728
66	Notes Payable to Assoc. Companies (233)		
67	Accounts Payable to Assoc. Companies (234)		36,168
68	Customer Deposits (235)		78,872
69	Taxes Accrued (236)		(919)
70	Interest Accrued (237)		73,493
71	Dividends Declared (238)		
72	Tax Collections Payable (241)		33
73	Misc Current & Accrued Liabilities (242)		182,695
74	Total Current & Accrued Liabilities	SUM L64 to L73	$1,169,506
75			
76	**Other Deferred Credits**		
77	Customer Advances for Construction (252)		$4,172
78	Other Deferred Credits (253)		5,796
79	Other Regulatory Liabilities (254)		282,725
80	Deferred Investment Tax Credit (255)		286
81	Unamortized Gain on Reacquired Debt (257)		
82	Accumulated Deferred Income Taxes (281-283)		2,575,325
83	Total Other Deferred Credits	SUM L77 to L82	$2,868,304
84			
85	**TOTAL LIABILITIES AND OTHER CREDITS**	L45+L53+L61+L74+L83	$18,529,402

			(1)	(2)	(3)
Line No.	Category	Description	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$1,678,305		$1,678,305
2		Electric Cost Revenue	1,071,200		1,071,200
3		Transmission - All Classes	199,791		199,791
4		Other Revenues	326,479	$278,457	48,022
5		Total Operating Revenues	$3,275,775	$278,457	$2,997,318
6					
7	**Total Operating Expenses**	Operation & Maintenance Expenses	$2,138,595	$89,358	$2,049,237
8		Depreciation & Amortization Expense	368,879	49,882	318,997
9		Amortization of Regulatory Expense			
10		Taxes Other Than Income Taxes - Other	202,036	4,519	197,517
11		Total Operating Expenses	$2,709,509	$143,758	$2,565,751
12					
13	**Net Utility Operating Income Before Income Tax**		**$566,265**	**$134,698**	**$431,567**

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	440.0	$952,140		$952,140
2			Residential - House Heating	440.1	183,381		183,381
3			C & I Small	442.0	293,772		293,772
4			C & I Large	442.1	218,495		218,495
5			Street Lighting	444.0	8,121		8,121
6			Railroads & Railways	446.0	22,396		22,396
7			Intercompany	448.0			
8			Transmission - All Classes		199,791		199,791
9			Sub-total - Customer & Distribution Revenues		$1,878,096		$1,878,096
10							
11		Electric Cost Revenue	Residential	440.0	$689,404		$689,404
12			Residential - House Heating	440.1	180,937		180,937
13			C & I Small	442.0	148,035		148,035
14			C & I Large	442.1	52,022		52,022
15			Street Lighting	444.0	801		801
16			Intercompany	448.0			
17			Sub-total - Electric Cost Revenue		$1,071,200		$1,071,200
18							
19		Other Operating Revenues	Forfeited Discounts	450.0	$12,224		$12,224
20			Miscellaneous Service Revenues	451.0	3,684		3,684
21			Rent For Electric Property	454.0	33,265	$10,685	22,580
22			Other Electric Revenues	456.0	9,534		9,534
23			Transmission of Electricity for Others	456.1	267,772	267,772	
24			Sub-total - Other Operating Revenues		$326,479	$278,457	$48,022
25							
26			**TOTAL OPERATING REVENUES**		$3,275,775	$278,457	$2,997,318
27							

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
28	**Operating Expenses**	Operation & Maintenance Expenses	Purchased Power	555.0	$1,003,713		$1,003,713
29			Operation & Supervision	560.0	8,806	$8,806	
30			Load Dispatching	561.0			
31			Scheduling, System Control & Dispatch	561.4	93,988		93,988
32			Transmission Service Studies	561.6			
33			Generation Service Studies	561.7			
34			Reliability, Planning & Standard Development	561.8	92,919		92,919
35			Station Expense	562.0	490	490	
36			Overhead Lines	563.0	637	637	
37			Underground Lines Expense	564.0			
38			Miscellaneous Expense	566.0	17,917	17,917	
39			Rents	567.0	15,996	15,996	
40			Maintenance of Structures	569.0	(38)	(38)	
41			Maintenance of Computer Hardware	569.1	84	84	
42			Maintenance of Computer Software	569.2	84	84	
43			Maintenance of Communication Equipment	569.3	130	130	
44			Maintenance of Station Equipment	570.0	14,348	14,348	
45			Maintenance of Overhead Lines	571.0	12,081	12,081	
46			Maintenance of Underground Lines	572.0	240	240	
47			Maintenance of Misc Transmission Plant	573.0	11,432	11,432	
48			Operation & Supervision	580.0	1,271		1,271
49			Load Dispatching	581.0			
50			Station Expenses	582.0	816		816
51			Overhead Lines Expenses	583.0	17,513		17,513
52			Underground Lines Expense	584.0	14,687		14,687
53			Meter Expenses	586.0	7,801		7,801
54			Customer Installations Expense	587.0	14,386		14,386
55			Miscellaneous Expense	588.0	90,014		90,014
56			Rents	589.0	3,658		3,658
57			Maintenance of Structures	591.0	6,622		6,622
58			Maintenance of Station Equipment	592.0	18,529		18,529
59			Maintenance of Overhead Lines	593.0	189,290		189,290
60			Maintenance of Underground Lines	594.0	38,602		38,602

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FPFTY Amount	Non-Jurisdictional	Jurisdictional
61			Maintenance of Line Transformers	595.0	2,378		2,378
62			Maintenance of Street Lighting & Signal Systems	596.0	1,990		1,990
63			Maintenance of Misc. Distribution	598.0	20,293		20,293
64			Supervision	901.0			
65			Meter Reading	902.0	976		976
66			Customer Records and Collection	903.0	105,441		105,441
67			Uncollectible Accounts	904.0	38,095		38,095
68			Miscellaneous Customer Accounts	905.0	3,295		3,295
69			Customer Assistance	908.0	101,517		101,517
70			Informational & Instructional	909.0	1,407		1,407
71			Miscellaneous Customer & Informational	910.0	992		992
72			Demonstrating & Selling	912.0	414		414
73			Miscellaneous Sales	916.0			
74			Administrative and General Salaries	920.0	22,337	(7,552)	29,889
75			Office Supplies and Expenses	921.0	4,628	1,063	3,566
76			Administrative Expenses Transferred-Credit	922.0			
77			Outside Service Employed	923.0	98,279	10,130	88,149
78			Property Insurance	924.0	833	91	741
79			Injuries & Damages	925.0	12,396	75	12,322
80			Employee Pensions and Benefits	926.0	26,786	2,043	24,743
81			Regulatory Commission Expenses	928.0	9,839	288	9,551
82			Duplicate Charges-Credit	929.0	(1,634)	(542)	(1,092)
83			Miscellaneous General Expenses	930.2	3,134	607	2,527
84			Maintenance of General Plant	935.0	9,183	946	8,237
85				Sub-total - O&M Expenses	$2,138,595	$89,358	$2,049,237
86							

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FPFTY Amount	Non-Jurisdictional	Jurisdictional
87		Depreciation & Amortization Expense	Depreciation & Amortization Expense	403.0	$309,959	$41,058	$268,901
88				404.0	58,920	8,824	50,096
89			Sub-total - Depreciation & Amortization Expense		$368,879	$49,882	$318,997
90							
91		Amortization of Regulatory Expense	Amortization of Regulatory Expense	407.3			
92			Sub-total - Amortization of Regulatory Expense				
93							
94		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	408.1	$202,036	$4,519	$197,517
95			Sub-total -Taxes Other Than Income Taxes - Other		$202,036	$4,519	$197,517
96							
97			**TOTAL OPERATING EXPENSES**		$2,709,509	$143,758	$2,565,751
98							
99			**NET UTILITY OPERATING INCOME BEFORE INCOME TAX**		**$566,265**	**$134,698**	**$431,567**
100							

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Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	440.0	$952,140		$952,140
2			Residential - House Heating	440.1	183,381		183,381
3			C & I Small	442.0	293,772		293,772
4			C & I Large	442.1	218,495		218,495
5			Railroads & Railways	446.0	8,121		8,121
6			Street Lighting	444.0	22,396		22,396
7			Intercompany	448.0			
8			Transmission - All Classes		199,791		199,791
9			Sub-total - Customer & Distribution Revenue		$1,878,096		$1,878,096
10							
11		**Electric Cost Revenue**	Residential	440.0	$689,404		$689,404
12			Residential - House Heating	440.1	180,937		180,937
13			C & I Small	442.0	148,035		148,035
14			C & I Large	442.1	52,022		52,022
15			Railroads & Railways	444.0			
16			Street Lighting	446.0	801		801
17			Intercompany	448.0			
18			Sub-total - Electric Cost Revenue		$1,071,200		$1,071,200
19							
20			**TOTAL OPERATING REVENUE**		$2,949,296		$2,949,296
21							
22	**OTHER REVENUE**	**Other Operating Revenue**	Forfeited Discounts	450.0	$12,224		$12,224
23			Miscellaneous Service Revenues	451.0	3,684		3,684
24			Sub-total - Other Operating Revenue		$15,908		$15,908
25							
26		**Other Electric Revenue**	Rent For Electric Property	454.0	$33,265	$10,685	$22,580
27			Other Electric Revenues	456.0	9,534		9,534
28			Transmission of Electricity for Others	456.1	267,772	267,772	
29			Sub-total - Other Electric Revenue		$310,571	$278,457	$32,114
30							
31			**TOTAL OTHER REVENUE**		$326,479	$278,457	$48,022
32							
33			**TOTAL REVENUE**		**$3,275,775**	**$278,457**	**$2,997,318**

Line No.	Category	Description	Account	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**POWER SUPPLY EXPENSES**	Power Supply	Purchased Power	555.0	$1,003,713		$1,003,713
2			**TOTAL POWER SUPPLY EXPENSES**		$1,003,713		$1,003,713
3							
4	**TRANSMISSION EXPENSE**	Transmission Operations	Operation & Supervision	560.0	$8,806	$8,806	
5			Load Dispatching	561.0			
6			Scheduling, System Control & Dispatch	561.4	93,988		93,988
7			Transmission Service Studies	561.6			
8			Generation Service Studies	561.7			
9			Reliability, Planning & Standard Development	561.8	92,919		92,919
10			Station Expense	562.0	490	490	
11			Overhead Lines	563.0	637	637	
12			Underground Lines Expense	564.0			
13			Miscellaneous Expense	566.0	17,917	17,917	
14			Rents	567.0	15,996	15,996	
15			Sub-total Transmission Operations	SUM L4 to L14	$230,754	$43,847	$186,907
16							
17		Transmission Maintenance	Maintenance of Structures	569.0	($38)	($38)	
18			Maintenance of Computer Hardware	569.1	84	84	
19			Maintenance of Computer Software	569.2	84	84	
20			Maintenance of Communication Equipment	569.3	130	130	
21			Maintenance of Station Equipment	570.0	14,348	14,348	
22			Maintenance of Overhead Lines	571.0	12,081	12,081	
23			Maintenance of Underground Lines	572.0	240	240	
24			Maintenance of Misc Transmission Plant	573.0	11,432	11,432	
25			Sub-total Transmission Maintenance	SUM L17 to L24	$38,362	$38,362	
26							
27			**TOTAL TRANSMISSION EXPENSE**	L15 + L25	$269,116	$82,208	$186,907
28							
29	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation & Supervision	580.0	$1,271		$1,271
30			Load Dispatching	581.0			
31			Station Expenses	582.0	816		816
32			Overhead Lines Expenses	583.0	17,513		17,513
33			Underground Lines Expense	584.0	14,687		14,687
34			Meter Expenses	586.0	7,801		7,801
35			Customer Installations Expense	587.0	14,386		14,386
36			Miscellaneous Expense	588.0	90,014		90,014
37			Rents	589.0	3,658		3,658
38			Sub-total Distribution Operations	SUM L29 to L37	$150,143		$150,143
39							
40		Distribution Maintenance	Maintenance of Structures	591.0	6,622		6,622
41			Maintenance of Station Equipment	592.0	18,529		18,529
42			Maintenance of Overhead Lines	593.0	189,290		189,290
43			Maintenance of Underground Lines	594.0	38,602		38,602
44			Maintenance of Line Transformers	595.0	2,378		2,378
45			Maintenance of Street Lighting & Signal Systems	596.0	1,990		1,990
46			Maintenance of Misc. Distribution	598.0	20,293		20,293

Line No.	Category	Description	Account	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
47			Sub-total Distribution Maintenance	SUM L40 to L46	$277,703		$277,703
48							
49			**TOTAL DISTRIBUTION EXPENSE**	L38 + L47	$427,846		$427,846
50							
51	**CUSTOMER ACCOUNTS**	Customer Accounts	Supervision	901.0			
52			Meter Reading	902.0	976		976
53			Customer Records and Collection	903.0	105,441		105,441
54			Uncollectible Accounts	904.0	38,095		38,095
55			Miscellaneous Customer Accounts	905.0	3,295		3,295
56			**TOTAL CUSTOMER ACCOUNTS**	SUM L51 to L55	$147,808		$147,808
57							
58	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$101,517		$101,517
59			Informational & Instructional	909.0	1,407		1,407
60			Miscellaneous Customer & Informational	910.0	992		992
61			**TOTAL CUSTOMER SERVICE & INFORMATION**	SUM L58 to L60	$103,916		$103,916
62							
63	**SALES**	Sales Expense	Demonstrating & Selling	912.0	$414		$414
64			Miscellaneous Sales	916.0			
65			**TOTAL SALES EXPENSE**	SUM L63 to L64	$414		$414
66							
67	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$22,337	($7,552)	$29,889
68			Office Supplies and Expenses	921.0	4,628	$1,063	3,566
69			Administrative Expenses Transferred-Credit	922.0			
70			Outside Service Employed	923.0	98,279	$10,130	88,149
71			Property Insurance	924.0	833	$91	741
72			Injuries & Damages	925.0	12,396	$75	12,322
73			Employee Pensions and Benefits	926.0	26,786	$2,043	24,743
74			Regulatory Commission Expenses	928.0	9,839	$288	9,551
75			Duplicate Charges-Credit	929.0	(1,634)	($542)	(1,092)
76			Miscellaneous General Expenses	930.2	3,134	$607	2,527
77			Sub-total A&G Operations	SUM L67 to L76	$176,599	$6,204	$170,395
78							
79		A&G Maintenance	Maintenance of General Plant	935.0	9,183	946	8,237
80							
81			TOTAL ADMINISTRATION & GENERAL	L77 + L79	$185,781	$7,150	$178,632
82							
83			**TOTAL O&M EXPENSE**	L2+L27+L49+L56+L61+L65+L81	$2,138,595	$89,358	$2,049,237
84							
85			TOTAL OPERATIONS EXPENSE		$1,822,531	$50,996	$1,771,534
86			TOTAL MAINTENANCE EXPENSE		316,064	38,362	277,703
87			**TOTAL O&M EXPENSE**	L85 + L86	**$2,138,595**	**$89,358**	**$2,049,237**

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Line No.	Category	Description	Description	Account	FPFTY Amount	Percent to Non-Jurisdiction	Non-Jurisdictional	Jurisdictional
1	**Distribution**	**A&G Operations**	Administrative and General Salaries	920.0	$29,889	0.0000%		$29,889
2			Office Supplies and Expenses	921.0	3,545	0.0000%		3,545
3			Administrative Expenses Transferred-Credit	922.0		0.0000%		
4			Outside Service Employed	923.0	88,149	0.0000%		88,149
5			Property Insurance	924.0	741	0.0000%		741
6			Injuries and Damages	925.0	12,322	0.0000%		12,322
7			Employee Pensions and Benefits	926.0	24,743	0.0000%		24,743
8			Regulatory Commission Expenses	928.0	9,551	0.0000%		9,551
9			Duplicate Charges-Credit	929.0	(1,092)	0.0000%		(1,092)
10			Miscellaneous General Expenses	930.2	2,527	0.0000%		2,527
11			Sub-total A&G Operations - Distribution	SUM L1 to L10	$170,373			$170,373
12								
13		**A&G Maintenance**	Maintenance of General Plant	935.0	$8,237	0.0000%		$8,237
14			**ADMINISTRATION & GENERAL - DISTRIBUTION**	L11 + L13	$178,610			$178,610
15								
16	**Transmission**	**A&G Operations**	Administrative and General Salaries	920.0	($7,552)	100.0000%	($7,552)	
17			Office Supplies and Expenses	921.0	1,060	100.0000%	1,060	
18			Administrative Expenses Transferred-Credit	922.0		100.0000%		
19			Outside Service Employed	923.0	10,130	100.0000%	10,130	
20			Property Insurance	924.0	91	100.0000%	91	
21			Injuries and Damages	925.0	75	100.0000%	75	
22			Employee Pensions and Benefits	926.0	2,043	100.0000%	2,043	
23			Regulatory Commission Expenses	928.0	288	100.0000%	288	
24			Duplicate Charges-Credit	929.0	(542)	100.0000%	(542)	
25			Miscellaneous General Expenses	930.2	607	100.0000%	607	
26			Sub-total A&G Operations - Transmission	SUM L16 to L25	$6,201		$6,201	
27								
28		**A&G Maintenance**	Maintenance of General Plant	935.0	$946	100.0000%	$946	
29			**ADMINISTRATION & GENERAL - TRANSMISSION**	L26 + L28	$7,147		$7,147	
30								

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Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
31	**General**	**A&G Operations**	Administrative and General Salaries	920.0		12.3730%		
32			Office Supplies and Expenses	921.0	24	12.3730%	3	21
33			Administrative Expenses Transferred-Credit	922.0		12.3730%		
34			Outside Service Employed	923.0		12.3730%		
35			Property Insurance	924.0		12.3730%		
36			Injuries and Damages	925.0		12.3730%		
37			Employee Pensions and Benefits	926.0		12.3730%		
38			Regulatory Commission Expenses	928.0		12.3730%		
39			Duplicate Charges-Credit	929.0		12.3730%		
40			Miscellaneous General Expenses	930.2	0	12.3730%	0	0
41			Sub-total A&G Operations - General	SUM L31 to L40	$25		$3	$22
42								
43		**A&G Maintenance**	Maintenance of General Plant	935.0	$0	12.3730%	$0	$0
44			**ADMINISTRATION & GENERAL - GENERAL**	L41 + L43	$25		$3	$22
45								
46	**TOTAL**	**A&G Operations**	Administrative and General Salaries	920.0	$22,337		($7,552)	$29,889
47			Office Supplies and Expenses	921.0	4,628		1,063	3,566
48			Administrative Expenses Transferred-Credit	922.0				
49			Outside Service Employed	923.0	98,279		10,130	88,149
50			Property Insurance	924.0	833		91	741
51			Injuries & Damages	925.0	12,396		75	12,322
52			Employee Pensions and Benefits	926.0	26,786		2,043	24,743
53			Regulatory Commission Expenses	928.0	9,839		288	9,551
54			Duplicate Charges-Credit	929.0	(1,634)		(542)	(1,092)
55			Miscellaneous General Expenses	930.2	3,134		607	2,527
56			Sub-total A&G Operations - TOTAL	SUM L46 to L55	$176,599		$6,204	$170,395
57								
58		**A&G Maintenance**	Maintenance of General Plant	935.0	$9,183		$946	$8,237
59			**ADMINISTRATION & GENERAL - TOTAL**	L56 + L58	$185,781		$7,150	$178,632

		(1)	(2)	(3)	(4)
Line No.	Description	Percentage	Total	Transmission Elimination	Distribution
1	Public Utility Real Tax (PURTA) Total Expense	17.825%	$6,924	($1,234)	$5,690
2	Use Tax Accrued	17.825%	2,443	(435)	2,007
3	Real Estate Tax Accrued	17.825%	5,988	(1,067)	4,920
4	Miscellaneous TOTI	12.373%			
5	Payroll Tax Accrued	12.373%	14,402	(1,782)	12,620
6	Gross Receipt Tax		172,280		172,280
7	**Total**		**$202,036**	**($4,519)**	**$197,517**

Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effectivel nterest Rate	Average Weighted Cost Rate	Annualized Cost
				(1)	(2)	(3)	(4)	(5)	(6)
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $350 - 3.15% - Due 10-15-2025						
2								
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		$75,000		6.00%		
4					1.14%		0.07%	
5		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
6					4.56%		0.28%	
7		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
8					2.66%		0.15%	
9		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
10					3.80%		0.19%	
11		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.21%		
12					4.56%		0.19%	
13		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
14					4.94%		0.19%	
15		PECO - FMB - $650 - 3.90% - Due 3-1-2048		650,000		4.08%		
16					9.87%		0.40%	
17		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
18					4.94%		0.15%	
19		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
20					5.32%		0.15%	
21		PECO - FMB - $375 - 3.05% - Due 3-15-2051		375,000		3.11%		
22					5.70%		0.18%	
23		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.90%		
24					5.70%		0.17%	
25		PECO - FMB - $350 - 4.60% - Due 5-15-2052		350,000		4.71%		
26					5.32%		0.25%	
27		PECO - FMB - $425 - 4.375% - Due 8-15-2052		425,000		4.46%		
28					6.46%		0.29%	
29		PECO - FMB - $575 - 4.90% - Due 6-15-2033		575,000		5.03%		
30					8.73%		0.44%	
31		PECO - FMB - $575 - 5.46% - Due 9-1-54		575,000		5.53%		
32					8.73%		0.48%	
33		PECO - FMB - $975 - 5.46% - Due 9-1-55		975,000		5.53%		
34					14.81%		0.82%	
35								
36		Sub-total Mortgage Bonds	SUM L1 to L35	$6,400,000	97.20%		4.40%	
37								
38	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.46%		
39					1.22%		0.09%	
40		PECO - TOPRS - $0.8 - Var (6.75%) - Due 4-6-2028		805		6.75%		
41					0.01%			
42		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
43					1.57%		0.09%	
44								
45		Sub-total Capital Securities	SUM L38 to L43	$184,419	2.80%		0.18%	
46								
47		Total Long-Term Debt	L36 + L45	$6,584,419	100.00%		4.58%	
48								
49		Adjustments for Tenders & Calls		(521)				
50								
51		Net Long-Term Debt	L47 + L49	$6,583,898				
52								
53		Annualized Cost		301,566				
54								
55		Adjustment for Tenders & Calls Reacquired		68				
56								
57		**Total**	L53 + L55	$301,634				4.58%

	(1)	(2)	(3)	(4)
Line No.	Description	Capitalization	Capitalization Ratio	Embedded Cost	Return %
1					
2	Long-Term Debt	$6,583,898	46.60%	4.58%	2.13%
3					
4	Common Equity	$7,545,824	53.40%	10.95%	5.85%
5					
6	Total	$14,129,722	100.00%		7.98%

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		(1)	(2)	(3)	(4)
Line No.	Description	Reference	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	Utility Plant	C-2	$13,491,056	$2,248,150	$11,242,906
2	Accumulated Depreciation	C-3	2,913,861	660,134	2,253,728
3	Common Plant	C-8	555,965		555,965
4	**Net Plant in Service**	L1 - L2 + L3	$11,133,160	$1,588,017	$9,545,143
5					
6	Working Capital	C-4	$214,843		$214,843
7	Accumulated Deferred Income Taxes	C-6	(596,644)		(596,644)
8	Customer Deposits	C-7	(57,291)		(57,291)
9	Customer Advances for Construction	C-9	(2,889)		(2,889)
10	Material & Supplies	C-11	30,350		30,350
11	ADIT - Reg Liability	C-12	(277,875)		(277,875)
12	**Total Measures of Value**	SUM L4 to L11	$10,443,654	$1,588,017	$8,855,637

Line No.	Category	Account	Reference	FPFTY Amount	Non-Jurisdictional	Jurisdictional
			(1)	(2)	(3)	(4)
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents		$163	$20	$143
3		E303 - Misc Intangible Plant		159,584	14,388	145,196
4		Sub-total Intangible Plant	SUM L1 to L3	$159,746	$14,408	$145,339
5						
6	**Transmission Plant**	E350 - Land and Land Rights		$75,731	$75,731	
7		E352 - Structures and Improvements		113,192	113,192	
8		E353 - Station Equipment		1,097,896	1,097,896	
9		E354 - Towers and Fixtures		294,157	294,157	
10		E355 - Poles and Fixtures		36,485	36,485	
11		E356 - Overhead Conductors, Devices		357,410	357,410	
12		E357 - Underground Conduit		68,327	68,327	
13		E358 - Undergrnd Conductors, Devices		147,404	147,404	
14		E359 - Roads and Trails		2,813	2,813	
15		E359.1 - ARO Costs Transmission Plt		502	502	
16		Sub-total Transmission Plant	SUM L6 to L15	$2,193,919	$2,193,919	
17						
18	**Distribution Plant**	E360 - Land and Land Rights		$54,159		$54,159
19		E361 - Structures and Improvements		255,582		255,582
20		E362 - Station Equipment		1,404,950		1,404,950
21		E364 - Poles, Towers and Fixtures		1,492,502		1,492,502
22		E365 - Overhead Conductors, Devices		2,382,803		2,382,803
23		E366 - Underground Conduit		1,045,522		1,045,522
24		E367 - Undergrnd Conductors, Devices		2,284,412		2,284,412
25		E368 - Line Transformers		930,272		930,272
26		E369 - Services		503,567		503,567
27		E370 - Meters		369,190		369,190
28		E371 - Installs on Customer Premiss		13,772		13,772
29		E373 - Street Lighting, Signal Systems		76,447		76,447
30		E374 - ARO Costs Distribution Plant		2,353		2,353
31		Sub-total Distribution Plant	SUM L18 to L30	$10,815,532		$10,815,532
32						
33	**General Plant**	E389 - Land and Land Rights		$1,063	$132	$932
34		E390 - Structures and Improvements		50,977	6,307	44,670
35		E391 - Office Furniture, Equipment		21,610	2,674	18,937
36		E392 - Transportation Equipment				
37		E393 - Stores Equipment		44	5	38
38		E394 - Tools, Shop, Garage Equipment		56,585	7,001	49,583
39		E395 - Laboratory Equipment		150	19	132
40		E396 - Power Operated Equipment				
41		E397 - Communication Equipment		188,797	23,360	165,437
42		E398 - Miscellaneous Equipment		716	89	627
43		E399 - Other Tangible Property				
44		E399.1 - ARO Costs General Plant		1,916	237	1,679
45		Sub-total General Plant	SUM L33 to L44	$321,859	$39,824	$282,035
46						
47		**Total**	L4+L16+L31+L45	**$13,491,056**	**$2,248,150**	**$11,242,906**

(1)

Line No.	Category	Account	Additions to Plant
1	**Intangible Plant**	E303 - Misc Intangible Plant	$39,375
2		Sub-total Intangible Plant	$39,375
3			
4	**Transmission Plant**	E350 - Land and Land Rights	($0)
5		E352 - Structures and Improvements	4,224
6		E353 - Station Equipment	33,531
7		E354 - Towers and Fixtures	1,047
8		E355 - Poles and Fixtures	2,457
9		E356 - Overhead Conductors, Devices	28,138
10		E357 - Underground Conduit	9,172
11		E358 - Undergrnd Conductors, Devics	7,317
12		E359 - Roads and Trails	68
13		Sub-total Transmission Plant	$85,954
14			
15	**Distribution Plant**	E361 - Structures and Improvements	$24,160
16		E362 - Station Equipment	82,485
17		E364 - Poles, Towers and Fixtures	187,472
18		E365 - Overhead Conductors, Devices	234,850
19		E366 - Underground Conduit	141,528
20		E367 - Undergrnd Conductors, Devics	260,419
21		E368 - Line Transformers	94,706
22		E369 - Services	18,305
23		E370 - Meters	11,333
24		E373 - Street Lighting,Signal Systm	5,828
25		Sub-total Distribution Plant	$1,061,088
26			
27	**General Plant**	E390 - Structures and Improvements	$94
28		E391 - Office Furniture, Equipment	2,962
29		E394 - Tools, Shop, Garage Equipmnt	3,084
30		E397 - Communication Equipment	5,317
31		E398 - Miscellaneous Equipment	38
32		Sub-total General Plant	$11,495
33			
34		**Total**	**$1,197,911**

(1)

Line No.	Category	Account	Plant Retirements
1	**Intangible Plant**	E303 - Misc Intangible Plant	($37,729)
2		Sub-total Intangible Plant	($37,729)
3			
4	**Transmission Plant**	E352 - Structures and Improvements	($73)
5		E353 - Station Equipment	(3,590)
6		E354 - Towers and Fixtures	(103)
7		E355 - Poles and Fixtures	(0)
8		E356 - Overhead Conductors, Devices	(72)
9		E357 - Underground Conduit	(7)
10		E358 - Undergrnd Conductors, Devics	(38)
11		E359.1 - ARO Costs Transmission Plt	(1)
12		Sub-total Transmission Plant	($3,884)
13			
14	**Distribution Plant**	E361 - Structures and Improvements	($669)
15		E362 - Station Equipment	(3,172)
16		E364 - Poles, Towers and Fixtures	(20,980)
17		E365 - Overhead Conductors, Devices	(16,652)
18		E366 - Underground Conduit	(835)
19		E367 - Undergrnd Conductors, Devics	(17,858)
20		E368 - Line Transformers	(16,468)
21		E369 - Services	(198)
22		E370 - Meters	(196)
23		E373 - Street Lighting,Signal Systm	(715)
24		E374 - ARO Costs Distribution Plt	(170)
25		Sub-total Distribution Plant	($77,913)
26			
27	**General Plant**	E390 - Structures and Improvements	($70)
28		E391 - Office Furniture, Equipment	(7,198)
29		E393 - Stores Equipment	(1)
30		E394 - Tools, Shop, Garage Equipmnt	(1,060)
31		E395 - Laboratory Equipment	(52)
32		E397 - Communication Equipment	(2,098)
33		E398 - Miscellaneous Equipment	(25)
34		E399.1 - ARO Costs General Plt	(21)
35		Sub-total General Plant	($10,525)
36			
37		**Total**	**($130,050)**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FPFTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	E301 - Organization Costs						
2								
3		E302 - Franchises and Consents	$163	100.00%	$163	87.63%	$143	$20
4			$163		$163		$143	$20
5								
6		E303 - Misc Intangible Plant	$159,584	100.00%	$159,584	90.98%	$145,196	$14,388
7			$159,584		$159,584		$145,196	$14,388
8								
9		Sub-total Intangible Plant	$159,746		$159,746		$145,339	$14,408
10								
11	**Transmission Plant**	E350 - Land and Land Rights	$75,731	100.00%	$75,731			$75,731
12			$75,731		$75,731			$75,731
13								
14		E352 - Structures and Improvements	113,192	100.00%	113,192			113,192
15			113,192		113,192			113,192
16								
17		E353 - Station Equipment	1,097,896	100.00%	1,097,896			1,097,896
18			1,097,896		1,097,896			1,097,896
19								
20		E354 - Towers and Fixtures	294,157	100.00%	294,157			294,157
21			294,157		294,157			294,157
22								
23		E355 - Poles and Fixtures	36,485	100.00%	36,485			36,485
24			36,485		36,485			36,485
25								
26		E356 - Overhead Conductors, Devices	357,410	100.00%	357,410			357,410
27			357,410		357,410			357,410
28								
29		E357 - Underground Conduit	68,327	100.00%	68,327			68,327
30			68,327		68,327			68,327
31								
32		E358 - Undergrnd Conductors, Devices	147,404	100.00%	147,404			147,404
33			147,404		147,404			147,404
34								
35		E359 - Roads and Trails	2,813	100.00%	2,813			2,813
36			2,813		2,813			2,813
37								
38		E359.1 - ARO Costs Transmission Plt	502	100.00%	502			502
39			502		502			502
40								
41		Sub-total Transmission Plant	$2,193,919		$2,193,919			$2,193,919
42								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FPFTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
43	**Distribution Plant**	E360 - Land and Land Rights	$54,159	100.00%	$54,159	100.00%	$54,159	
44			$54,159		$54,159		$54,159	
45								
46		E361 - Structures and Improvements	255,582	100.00%	255,582	100.00%	255,582	
47			255,582		255,582		255,582	
48								
49		E362 - Station Equipment	1,404,950	100.00%	1,404,950	100.00%	1,404,950	
50			1,404,950		1,404,950		1,404,950	
51								
52		E364 - Poles, Towers and Fixtures	1,492,502	100.00%	1,492,502	100.00%	1,492,502	
53			1,492,502		1,492,502		1,492,502	
54								
55		E365 - Overhead Conductors, Devices	2,382,803	100.00%	2,382,803	100.00%	2,382,803	
56			2,382,803		2,382,803		2,382,803	
57								
58		E366 - Underground Conduit	1,045,522	100.00%	1,045,522	100.00%	1,045,522	
59			1,045,522		1,045,522		1,045,522	
60								
61		E367 - Undergrnd Conductors, Devices	2,284,412	100.00%	2,284,412	100.00%	2,284,412	
62			2,284,412		2,284,412		2,284,412	
63								
64		E368 - Line Transformers	930,272	100.00%	930,272	100.00%	930,272	
65			930,272		930,272		930,272	
66								
67		E369 - Services	503,567	100.00%	503,567	100.00%	503,567	
68			503,567		503,567		503,567	
69								
70		E370 - Meters	369,190	100.00%	369,190	100.00%	369,190	
71			369,190		369,190		369,190	
72								
73		E371 - Installs on Customer Premiss	13,772	100.00%	13,772	100.00%	13,772	
74			13,772		13,772		13,772	
75								
76		E373 - Street Lighting, Signal Systems	76,447	100.00%	76,447	100.00%	76,447	
77			76,447		76,447		76,447	
78								
79		E374 - ARO Costs Distribution Plant	2,353	100.00%	2,353	100.00%	2,353	
80		Electric Nonrecoverable 100%						
81			2,353		2,353		2,353	
82								
83		Sub-total Distribution Plant	$10,815,532		$10,815,532		$10,815,532	
84								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FPFTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
85	**General Plant**	E389 - Land and Land Rights	$1,063	100.00%	$1,063	87.63%	$932	$132
86			$1,063		$1,063		$932	$132
87								
88		E390 - Structures and Improvements	50,977	100.00%	50,977	87.63%	44,670	6,307
89			50,977		50,977		44,670	6,307
90								
91		E391 - Office Furniture, Equipment	21,610	100.00%	21,610	87.63%	18,937	2,674
92			21,610		21,610		18,937	2,674
93								
94		E393 - Stores Equipment	44	100.00%	44	87.63%	38	5
95			44		44		38	5
96								
97		E394 - Tools, Shop, Garage Equipment	56,585	100.00%	56,585	87.63%	49,583	7,001
98			56,585		56,585		49,583	7,001
99								
100		E395 - Laboratory Equipment	150	100.00%	150	87.63%	132	19
101			150		150		132	19
102								
103		E397 - Communication Equipment	188,797	100.00%	188,797	87.63%	165,437	23,360
104			188,797		188,797		165,437	23,360
105								
106		E398 - Miscellaneous Equipment	716	100.00%	716	87.63%	627	89
107			716		716		627	89
108								
109		E399.1 - ARO Costs General Plant	1,916	100.00%	1,916	87.63%	1,679	237
110			1,916		1,916		1,679	237
111								
112		Sub-total General Plant	$321,859		$321,859		$282,035	$39,824
113								
114								
115		**Total**	**$13,491,056**		**$13,491,056**		**$11,242,906**	**$2,248,150**

Line No.	Category	Account	Reference	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents				
3		E303 - Misc Intangible Plant		$59,245	$3,490	$55,755
4		Sub-total Intangible Plant	SUM L1 to L3	$59,245	$3,490	$55,755
5						
6	**Transmission Plant**	E350 - Land and Land Rights		($0)	($0)	
7		E352 - Structures and Improvements		31,474	31,474	
8		E353 - Station Equipment		265,819	265,819	
9		E354 - Towers and Fixtures		179,707	179,707	
10		E355 - Poles and Fixtures		4,503	4,503	
11		E356 - Overhead Conductors, Devices		100,684	100,684	
12		E357 - Underground Conduit		3,242	3,242	
13		E358 - Undergrnd Conductors, Devices		50,614	50,614	
14		E359 - Roads and Trails		2,247	2,247	
15		E359.1 - ARO Costs Transmission Plt		122	122	
16		Sub-total Transmission Plant	SUM L6 to L15	$638,410	$638,410	
17						
18	**Distribution Plant**	E360 - Land and Land Rights		$310		310
19		E361 - Structures and Improvements		52,846		$52,846
20		E362 - Station Equipment		533,251		533,251
21		E364 - Poles, Towers and Fixtures		82,042		82,042
22		E365 - Overhead Conductors, Devices		313,680		313,680
23		E366 - Underground Conduit		199,133		199,133
24		E367 - Undergrnd Conductors, Devices		206,658		206,658
25		E368 - Line Transformers		182,504		182,504
26		E369 - Services		213,095		213,095
27		E370 - Meters		235,464		235,464
28		E371 - Installs on Customer Premises		11,799		11,799
29		E373 - Street Lighting, Signal Systems		36,153		36,153
30		E374 - ARO Costs Distribution Plant		1,907		1,907
31		Sub-total Distribution Plant	SUM L18 to L30	$2,068,842		$2,068,842
32						
33	**General Plant**	E389 - Land and Land Rights				
34		E390 - Structures and Improvements		$18,173	$2,249	$15,924
35		E391 - Office Furniture, Equipment		12,790	1,582	11,207
36		E392 - Transportation Equipment				
37		E393 - Stores Equipment		32	4	28
38		E394 - Tools, Shop, Garage Equipmnt		25,759	3,187	22,572
39		E395 - Laboratory Equipment		142	18	125
40		E396 - Power Operated Equipment				
41		E397 - Communication Equipment		88,827	10,991	77,837
42		E398 - Miscellaneous Equipment		(238)	(29)	(208)
43		E399 - Other Tangible Property				
44		E399.1 - ARO Costs General Plt		1,879	232	1,646
45		Sub-total General Plant	SUM L33 to L44	$147,364	$18,234	$129,131
46						
47		**Total**	L4+L16+L31+L45	**$2,913,861**	**$660,134**	**$2,253,728**

Line No.	Description	Account	(1) FPFTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
1	**Intangible Plant**	E302 - Franchises and Consents						
2								
3								
4		E303 - Misc Intangible Plant	$59,245	100.00%	$59,245	94.11%	55,755	$3,490
5			$59,245	100.00%	$59,245	94.11%	$55,755	$3,490
6								
7		Sub-total Intangible Plant	$59,245		$59,245		$55,755	$3,490
8								
9	**Transmission Plant**	E350 - Land and Land Rights	($0)	100.00%	($0)			($0)
10			($0)		($0)			($0)
11								
12		E352 - Structures and Improvements	31,474	100.00%	31,474			31,474
13			31,474		31,474			31,474
14								
15		E353 - Station Equipment	265,819	100.00%	265,819			265,819
16			265,819		265,819			265,819
17								
18		E354 - Towers and Fixtures	179,707	100.00%	179,707			179,707
19			179,707		179,707			179,707
20								
21		E355 - Poles and Fixtures	4,503	100.00%	4,503			4,503
22			4,503		4,503			4,503
23								
24		E356 - Overhead Conductors, Devices	100,684	100.00%	100,684			100,684
25			100,684		100,684			100,684
26								
27		E357 - Underground Conduit	3,242	100.00%	3,242			3,242
28			3,242		3,242			3,242
29								
30		E358 - Undergrnd Conductors, Devices	50,614	100.00%	50,614			50,614
31			50,614		50,614			50,614
32								
33		E359 - Roads and Trails	2,247	100.00%	2,247			2,247
34			2,247		2,247			2,247
35								
36		E359.1 - ARO Costs Transmission Plt	122	100.00%	122			122
37			122		122			122
38								
39		Sub-total Transmission Plant	$638,410		$638,410			$638,410
40								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FPFTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
41	**Distribution Plant**	E360 - Land and Land Rights	310	100.00%	310	100.00%	310	
42			310		310		310	
43								
44		E361 - Structures and Improvements	$52,846	100.00%	$52,846	100.00%	$52,846	
45			$52,846		$52,846		$52,846	
46								
47		E362 - Station Equipment	533,251	100.00%	533,251	100.00%	533,251	
48			533,251		533,251		533,251	
49								
50		E364 - Poles, Towers and Fixtures	82,042	100.00%	82,042	100.00%	82,042	
51			82,042		82,042		82,042	
52								
53		E365 - Overhead Conductors, Devices	313,680	100.00%	313,680	100.00%	313,680	
54			313,680		313,680		313,680	
55								
56		E366 - Underground Conduit	199,133	100.00%	199,133	100.00%	199,133	
57			199,133		199,133		199,133	
58								
59		E367 - Undergrnd Conductors, Devices	206,658	100.00%	206,658	100.00%	206,658	
60			206,658		206,658		206,658	
61								
62		E368 - Line Transformers	182,504	100.00%	182,504	100.00%	182,504	
63			182,504		182,504		182,504	
64								
65		E369 - Services	213,095	100.00%	213,095	100.00%	213,095	
66			213,095		213,095		213,095	
67								
68		E370 - Meters	235,464	100.00%	235,464	100.00%	235,464	
69			235,464		235,464		235,464	
70								
71		E371 - Installs on Customer Premises	11,799	100.00%	11,799	100.00%	11,799	
72			11,799		11,799		11,799	
73								
74		E373 - Street Lighting, Signal Systems	36,153	100.00%	36,153	100.00%	36,153	
75			36,153		36,153		36,153	
76								
77		E374 - ARO Costs Distribution Plant	1,907	100.00%	1,907	100.00%	1,907	
78								
79			1,907		1,907		1,907	
80								
81		Sub-total Distribution Plant	$2,068,842		$2,068,842		$2,068,842	
82								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FPFTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
83	**General Plant**	E389 - Land and Land Rights						
84								
85								
86		E390 - Structures and Improvements	$18,173	100.00%	$18,173	87.63%	$15,924	$2,249
87			$18,173		$18,173		$15,924	$2,249
88								
89		E391 - Office Furniture, Equipment	12,790	100.00%	12,790	87.63%	11,207	1,582
90			12,790		12,790		11,207	1,582
91								
92		E393 - Stores Equipment	32	100.00%	32	87.63%	28	4
93			32		32		28	4
94								
95		E394 - Tools, Shop, Garage Equipmnt	25,759	100.00%	25,759	87.63%	22,572	3,187
96			25,759		25,759		22,572	3,187
97								
98		E395 - Laboratory Equipment	142	100.00%	142	87.63%	125	18
99			142		142		125	18
100								
101		E397 - Communication Equipment	88,827	100.00%	88,827	87.63%	77,837	10,991
102			88,827		88,827		77,837	10,991
103								
104		E398 - Miscellaneous Equipment	(238)	100.00%	(238)	87.63%	(208)	(29)
105			(238)		(238)		(208)	(29)
106								
107		E399.1 - ARO Costs General Plt	1,879	100.00%	1,879	87.63%	1,646	232
108			1,879		1,879		1,646	232
109								
110		Sub-total General Plant	$147,364		$147,364		$129,131	$18,234
111								
112		**Total**	**$2,913,861**		**$2,913,861**		**$2,253,728**	**$660,134**

Line No.	Category	Account	(1) Reference	(2) FPFTY Amount
1	**Electric - Intangible Plant**	E303 - Misc Intangible Plant		($0)
2		Sub-total Electric - Intangible Plant		($0)
3				
4	**Electric - Transmission**	E350 - Land and Land Rights		$0
5		E352 - Structures and Improvements		123
6		E353 - Station Equipment		2,704
7		E354 - Towers and Fixtures		177
8		E355 - Poles and Fixtures		76
9		E356 - Overhead Conductors, Devices		1,462
10		E357 - Underground Conduit		850
11		E358 - Undergrnd Conductors, Devics		1,172
12		E359 - Roads and Trails		4
13		Sub-total Electric - Transmission	SUM L4 to L12	$6,569
14				
15	**Electric - Distribution**	E361 - Structures and Improvements		$1,110
16		E362 - Station Equipment		5,746
17		E364 - Poles, Towers and Fixtures		16,669
18		E365 - Overhead Conductors, Devices		19,073
19		E366 - Underground Conduit		4,267
20		E367 - Undergrnd Conductors, Devics		20,169
21		E368 - Line Transformers		897
22		E369 - Services		708
23		E370 - Meters		207
24		E373 - Street Lighting, Signal Systems		114
25		Sub-total Electric - Distribution	SUM L15 to L24	$68,960
26				
27	**Electric - General Plant**	E390 - Structures and Improvements		$95
28		E391 - Office Furniture, Equipment		60
29		E394 - Tools, Shop, Garage Equipmnt		14
30		E397 - Communication Equipment		556
31		E398 - Miscellaneous Equipment		93
32		Sub-total Electric - General Plant	SUM L27 to L31	$818
33				
34		**Total**	Lines 2+13+25+32	**$76,347**

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	FPFTY Expenses	(Lead)/Lag Days	Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			51.95	
4					
5	Expense Lag Days				
6	Payroll (Dist Only)		$173,658	13.58	$2,358,858
7	Pension Expense		3,216	(167.00)	(537,107)
8	Commodity Purchased - [A]		995,523	35.71	35,548,467
9	Commodity Purchased - [B]		8,190	12.50	102,374
10	PJM Transmission Purchased - By-passable		91,766	12.50	1,147,070
11	PJM Transmission Purchased - Non By-passable		95,142	12.50	1,189,272
12	Other Expenses		590,497	40.07	23,662,420
13	Sub-Total O&M	SUM L6 to L12	$1,957,991		$63,471,354
14					
15	Payment to Suppliers		$1,082,504	37.88	$41,001,678
16					
17	Total O&M and POR Payments	L13 + L15	$3,040,496		$104,473,032
18					
19	O&M Expense / POR Payment Lag Days			34.36	
20					
21	Net Lead/(Lag) Days	L3 - L19		17.59	
22					
23	Days in Current Year			365	
24					
25	Operating Expenses Per Day		$8,330		
26					
27	Working Capital for O&M Expense		$146,519		
28					
29	Average Prepayments		$8,636		
30	Accrued Taxes		$80,039		
31	Interest Payments		($20,351)		
32					
33	**Total Working Capital Requirement**	SUM L27 to L31	**$214,843**		
34					
35	Pro Forma O&M Expense		$2,005,564		
36	Uncollectible Expense		47,572		
37	Pro Forma Cash O&M Expense	L35 - L36	$1,957,991		

		(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	Accounts Receivable Balance End of Month	Total Monthly Billing Revenue	A/R Turnover	Days Lag
1	Annual Number of Days					365
2						
3	December		$402,842			
4	January		453,446	$378,637		
5	February		445,195	329,190		
6	March		411,718	303,032		
7	April		408,197	278,953		
8	May		340,718	260,453		
9	June		347,805	288,753		
10	July		409,252	373,500		
11	August		386,093	404,999		
12	September		398,390	381,298		
13	October		308,580	293,722		
14	November		285,129	267,091		
15	December		341,788	320,380		
16						
17	Total	SUM L3 to L15	$4,939,151	$3,880,008		
18						
19	Average A/R Balance		13			
20						
21	Factor		$379,935	$3,880,008	10.21	35.74
22						
23	Collection Days Lag					35.74
24						
25	Billing and Revenue Recording Days Lag					1.00
26						
27	Billing Lag (Average Period)	365 / 12 * 0.5				15.21
28						
29	**Total Revenue Lag Days**	L23 + L25 + L27				**51.95**

Line No.	Category	Description	Reference	Payment Date	Mid-point of Service Period	Expense Amount	(Lead)/Lag Days	Dollar Days
			(1)	(2)	(3)	(4)	(5)	(6)
1	PAYROLL	Union & Non-Union Payroll				$167,922		
2		Paid Twice Per Month					13.58	
3		Weighted Payroll Dollar Value						$2,280,946
4								
5		**Payroll Lag**	SUM L1 to L3			$167,922	**13.58**	$2,280,946
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2025	7/1/2025	$3,300	(167.00)	($551,100)
12								
13		Sub-total	SUM L7 to L11			$3,300		($551,100)
14								
15		**Lag Days for Pension Payment**					**(167.00)**	
16								
17	PURCHASE COMMODITY COSTS	**Payment Lag - Contract Purchases**					**35.71**	
18		**Payment Lag - Spot Market/PJM Purchases**					**12.50**	
19		**Payment Lag - Payment to Suppliers**					**37.88**	
20								
21								
22	OTHER O & M EXPENSES	January				$16,812		$651,478
23		April				26,471		1,077,737
24		July				25,711		1,175,140
25		October				22,699		769,982
26								
27		**Lag Days for Other Expenses**	SUM L22 to L25			$91,693	**40.07**	$3,674,337

			(1)	(2)	(3)	(4)
Line No.	Months	Description	Number of CDs	Cash Disbursements	Dollar-Days	Expense Lag Days
1	January	Total Disbursements for Month	19,206	$337,934		
2		Total Disbursements for Expenses	1,354	$16,812	$651,478	38.75
3						
4	April	Total Disbursements for Month	33,541	$241,401		
5		Total Disbursements for Expenses	2,115	$26,471	$1,077,737	40.71
6						
7	July	Total Disbursements for Month	29,010	$256,674	-	
8		Total Disbursements for Expenses	1,842	$25,711	$1,175,140	45.70
9						
10	October	Total Disbursements for Month	22,765	$232,356	-	
11		Total Disbursements for Expenses	1,978	$22,699	$769,982	33.92
12	**TOTAL FOUR TEST MONTHS**					
13						
14	**Total Test Month Expense Disbursement**		7,289	$91,693	$3,674,337	**40.07**

Line No.	Description	Description	Payment Date	Mid Point Date	Lead/(Lag) Payment Days	Total Payment Amount	Payment Percentage	Payment Amount	Weighted Dollar Days
			(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**FEDERAL INCOME TAX**	First Payment	4/15/2025	7/1/2025	77	$113,465	25.00%	$28,366	$2,184,211
2		Second Payment	6/16/2025	7/1/2025	15	113,465	25.00%	28,366	425,496
3		Third Payment	9/15/2025	7/1/2025	(76)	113,465	25.00%	28,366	(2,155,844)
4		Fourth Payment	12/15/2025	7/1/2025	(167)	113,465	25.00%	28,366	(4,737,184)
5		Sub-total FEDERAL INCOME TAX					100.00%	$113,465	($4,283,322)
6									
7	**STATE INCOME TAX**	First Payment	3/17/2025	7/1/2025	106	$12,681	25.00%	$3,170	$336,042
8		Second Payment	6/16/2025	7/1/2025	15	12,681	25.00%	3,170	47,553
9		Third Payment	9/15/2025	7/1/2025	(76)	12,681	25.00%	3,170	(240,936)
10		Fourth Payment	12/15/2025	7/1/2025	(167)	12,681	25.00%	3,170	(529,425)
11		Sub-total STATE INCOME TAX					100.00%	$12,681	($386,765)
12									
13	**PURTA**	First Payment	5/1/2025	7/1/2025	61	$5,690	100.00%	$5,690	$347,061
14		Subtotal PURTA					100.00%	$5,690	$347,061
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Sub-total PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/9/2025	7/1/2025	22	$4,920	100.00%	$4,920	$108,248
23		Second Payment							
24		Sub-total PA PROPERTY TAX					100.00%	$4,920	$108,248
25									
26	**GROSS RECEIPTS TAX**	First Payment	3/17/2025	7/1/2025	106	$166,664	100.00%	$166,664	$17,666,417
27		Sub-total GROSS RECEIPTS TAX					100.00%	$166,664	$17,666,417

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Total Payment Amount	Weighted Dollar Days	Payment Lead/(Lag) Days	Revenue Lag Days	Net Payment Lead/(Lag) Days	Net Payment Lead/(Lag) Dollars Days	Average Daily Amount for Working Capital
1	FEDERAL INCOME TAX	$113,465	($4,283,322)	(37.75)	51.95	14.20	$1,611,158	$4,414
2	STATE INCOME TAX	$12,681	($386,765)	(30.50)	51.95	21.45	$271,998	$745
3	PURTA	$5,690	$347,061	61.00	51.95	112.95	$642,630	$1,761
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$4,920	$108,248	22.00	51.95	73.95	$363,859	$997
6	GROSS RECEIPTS TAX	$166,664	$17,666,417	106.00	51.95	157.95	$26,324,551	$72,122

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Measures of Value at End of FPFTY		$8,855,637
2	Long-Term Debt Ratio		46.60%
3	Embedded Cost of Long-Term Debt		4.58%
4	Pro Forma Interest Expense	L1 * L2 * L3	$189,004
5	Days in Curent Year		365
6	Daily Amount	L4 / L5	$518
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days	C-4	51.95
9	Interest Payment Lag Days	L8 - L7	(39.30)
10	**Total Interest for Working Capital**	L6 * L9	**($20,351)**

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Line No.	Description	Reference	EPRI Dues	EEI Dues	EAP Membership Dues	Prepaid Rents & Pole Attachments	PUC Assessment Electric	Land Leasing	Maintenance	IT License & Maintenance	Business Support Systems	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1	December					$331	$3,893	$194		$32	$217	$2,394	$0	$96	$448	$71	$327	$1,247	
2	January			$573		788	3,032			($0)	469	2,394	(18)	88	465	51	285	816	
3	February			521		745	2,425			$356	424	2,394	(35)	80	420	170	372	701	
4	March			469		558	1,819	188		$324	333	3,157	157	88	420	254	305	662	
5	April		$304	417	$237	392	1,213		244	$291	544	3,157	139	80	433	112	276	728	
6	May		203	365	138	212	606		195	$259	453	3,157	122	72	428	159	243	731	
7	June		203	313	118	170	0	181	195	$227	226	3,584	105	119	422	294	223	739	
8	July		203	261	99	641	5,155		195	$204	467	3,584	87	111	441	562	277	760	
9	August		203	208	79	453	4,495		195	$240	486	3,584	70	103	441	761	214	685	
10	September		101	156	59	624	5,779	175	195	$201	513	3,775	52	136	399	623	146	664	
11	October		101	104	39	469	5,205		195	$161	491	3,775	35	128	404	561	92	664	
12	November			52	20	284	4,630		195	$405	363	3,775	17	120	438	500	59	712	
13	December			0		234	4,055	168	195	$82	283	4,879	0	153	451	248	573	777	
14																			
15	Total	SUM L1 to L13	$1,319	$3,440	$788	$5,900	$42,307	$906	$1,804	$2,782	$5,270	$43,611	$731	$1,376	$5,610	$4,367	$3,392	$9,886	
16																			
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	67.41%	67.41%	67.41%	67.41%	74.50%	74.50%	74.50%	
18																			
19	Distribution Amount	L15 * L17	$1,319	$3,440	$788	$5,900	$42,307	$906	$1,804	$2,782	$5,270	$29,399	$493	$927	$3,782	$3,254	$2,527	$7,365	
20																			
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																			
23	Monthly Average	L19 / L21	$101	$265	$61	$454	$3,254	$70	$139	$214	$405	$2,261	$38	$71	$291	$250	$194	$567	
24																			
25	**Rate Case Amount**																		**$8,636**

Line No.	Description	(1) Midpoint of Prior Month Service Period to end of Month	(2) Payment Date Month after Service Period	(3) Additional Weekend or Holidays Extending Payment Date	(4) Lag Days	(5) Average
1	**Contract Purchases in FPFTY**					
2	January	15.50	19.00	1.00	35.50	
3	February	15.50	19.00	1.00	35.50	
4	March	14.00	19.00	1.00	34.00	
5	April	15.50	19.00	2.00	36.50	
6	May	15.00	19.00	1.00	35.00	
7	June	15.50	19.00	1.00	35.50	
8	July	15.00	19.00	2.00	36.00	
9	August	15.50	19.00	1.00	35.50	
10	September	15.50	19.00	3.00	37.50	
11	October	15.00	19.00	1.00	35.00	
12	November	15.50	19.00	1.00	35.50	
13	December	15.00	19.00	3.00	37.00	
14	**Payment Lag - Contract Purchases**					**35.71**
15						
16	**Spot Market Purchases in FPFTY and PJM Transmission Purchased**					
17		Service Period	Units	Service Period of Days	Lag Days	Total
18						
19	Service Period Weekly	Wed . to Tues.	Days	7.00		
20						
21	Days from Midpoint to End of Service				3.50	
22						
23	Payment Due on Friday of each Week				9.00	
24	**Payment Lag - Spot Market/PJM Purchases**					**12.50**
25						
26	**Payments to Suppliers**					
27		Payment Lag Days	Revenue Percentage	Weighted Lag Days	Lag Days	Total
28						
29	Residential	25.00	33%	8.34		
30	Nonresidential	20.00	67%	13.33		
31	Weighted Lag Days				21.67	
32						
33	Billing and Revenue Recording Days Lag				1.00	
34						
35	Billing Lag (Average Period)	365 / 12. * 0.5			15.21	
36						
37	Total POR Payment Lag Days	L31 + L33 + L35				**37.88**

Line No.	Test Year	Description	Reference	(1) Total Amount	(2) Percent to Utility	(3) Utility Amount	(4) Percent to Distribution	(5) Distribution Amount
1	**HTY**	ADIT - CIAC		($18,074)	100.00%	($18,074)	100.00%	($18,074)
2		ADIT - Common Plant		69,010	100.00%	69,010	63.22%	43,626
3		ADIT - Electric Common Plant		35,732	100.00%	35,732	82.17%	29,362
4		ADIT - Electric Distribution		619,210	100.00%	619,210	100.00%	619,210
5		ADIT - Corp. Alternative Minimum Tax		(60,332)	100.00%	(60,332)	100.00%	(60,332)
6		Sub-total	SUM L1 to L5	$645,546		$645,546		$613,793
7								
8	**FTY**	DIT - CIAC		($5,056)	100.00%	($5,056)	100.00%	($5,056)
9		DIT - Common Plant			100.00%		63.22%	
10		DIT - Electric Common Plant			100.00%		82.17%	
11		DIT - Electric Distribution		35,217	100.00%	35,217	100.00%	35,217
12		DIT - Corp. Alternative Minimum Tax		(48,211)	100.00%	(48,211)	100.00%	(48,211)
13		Sub-total	SUM L8 to L12	($18,050)		($18,050)		($18,050)
14								
15	**FPFTY**	DIT - CIAC		($5,035)	100.00%	($5,035)	100.00%	($5,035)
16		DIT - Common Plant			100.00%		63.22%	
17		DIT - Electric Common Plant			100.00%		82.17%	
18		DIT - Electric Distribution		27,673	100.00%	27,673	100.00%	27,673
19		DIT - Corp. Alternative Minimum Tax		(21,737)	100.00%	(21,737)	100.00%	(21,737)
20		Sub-total	SUM L15 to L19	$902		$902		$902
21								
22		**Total**	L6 + L13 + L20	**$628,397**		**$628,397**		**$596,644**

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Residential	Non-Residential	Total
1	December		$18,802	$31,587	$50,388
2	January		18,976	32,487	51,463
3	February		19,166	33,197	52,363
4	March		19,446	33,844	53,290
5	April		20,077	34,307	54,384
6	May		20,877	35,117	55,994
7	June		21,538	35,642	57,179
8	July		22,060	36,988	59,048
9	August		22,549	38,022	60,571
10	September		22,772	38,782	61,555
11	October		23,058	39,358	62,416
12	November		23,276	39,646	62,922
13	December		23,215	39,988	63,203
14					
15	Total	SUM L1 to L13	$275,812	$468,965	$744,777
16					
17	Average Monthly Balance	L15 / 13	$21,216	$36,074	$57,291
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$21,216
21	Small C&I				30,886
22	Large C&I				5,183
23	Other				5
24					
25	**Total**	SUM L20 to L23			**$57,291**

Line No.	Category	Account	Reference	FPFTY Amount	Allocated to Non Jurisdiction	Allocated to Jurisdiction
			(1)	(2)	(3)	(4)
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$221	$456
4						
5		E303 - Misc Intangible Plant		$337,580	$100,986	$236,594
6						
7		E389 - Land and Land Rights		$6,783	$2,211	$4,573
8						
9		E390 - Structures and Improvements		$432,164	$140,836	$291,328
10		E391 - Office Furniture, Equipment		82,575	26,910	55,665
11		E392 - Transportation Equipment		218,349	71,157	147,192
12		E393 - Stores Equipment		1,144	373	771
13		E394 - Tools, Shop, Garage Equipmnt		2,144	699	1,445
14		E396 - Power Operated Equipment		185	60	125
15		E397 - Communication Equipment		160,034	52,153	107,881
16		E398 - Miscellaneous Equipment		1,158	377	781
17		E399 - Other Tangible Property				
18		E399.1 - ARO Costs General Plant		803	262	541
19		Sub Total - General Plant	SUM L9 to L18	$898,556	$292,827	$605,729
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,243,596	$396,244	$847,352
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$156,223	$49,237	$106,986
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$70,406	$22,944	$47,462
31		E391 - Office Furniture, Equipment		35,258	11,490	23,768
32		E392 - Transportation Equipment		115,297	37,574	77,724
33		E393 - Stores Equipment		246	80	166
34		E394 - Tools, Shop, Garage Equipmnt		834	272	562
35		E396 - Power Operated Equipment		185	60	125
36		E397 - Communication Equipment		50,731	16,533	34,199
37		E398 - Miscellaneous Equipment		974	317	657
38		E399 - Other Tangible Property				
39		E399.1 - ARO Costs General Plant		(386)	(126)	(260)
40		Sub Total - General Plant	SUM L30 to L39	$273,546	$89,145	$184,401
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$429,769	$138,382	$291,387
42						
43		Net Common Plant	L20 - L41	$813,827	$257,861	$555,965
44						
45						
46		Common Plant in Service to Utility	L20	$1,243,596	$396,244	$847,352
47		Common Plant Accum Depreciation to Utility	L41	429,769	138,382	291,387
48		Net Common Plant to Utility	L46 - L47	$813,827	$257,861	$555,965

		(1)	(2)
Line No.	Description	Reference	Total
1	HTY 13-Month Average		
2	December		$2,662
3	January		2,509
4	February		2,978
5	March		3,239
6	April		3,066
7	May		2,900
8	June		2,423
9	July		2,393
10	August		2,049
11	September		3,859
12	October		3,861
13	November		2,764
14	December		2,855
15			
16	13-Month Total	SUM L2 to L14	$37,557
17			
18			
19	**Average Monthly Balance**	L16 / 13	**$2,889**

Line No.	Description	Reference	(1) Materials & Supplies	(2) Undistributed Stores Expense	(3) Total
1	HTY 13-Month Average				
2	December		$29,564	($0)	$29,564
3	January		30,031	(191)	29,840
4	February		28,319	(372)	27,947
5	March		26,573	(1,490)	25,083
6	April		26,183	(1,111)	25,072
7	May		26,568	(1,460)	25,108
8	June		27,575	(1,693)	25,882
9	July		28,584	(1,197)	27,387
10	August		33,678	(1,126)	32,553
11	September		34,598	(1,077)	33,522
12	October		34,602	(660)	33,943
13	November		36,708	(686)	36,023
14	December		39,019	0	39,019
15					
16	Total	SUM L2 to L14	$402,003	($11,061)	$390,942
17					
18	Distribution Expense Allocation Factor		100.00%	67.41%	
19					
20	Allocation to Distribution	L16 * L18	$402,003	($7,457)	
21					
22	**Average Monthly Balance**	L20 / 13	$30,923	($574)	**$30,350**

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			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - Distribution		$288,276	100.00%	$288,276	100.00%	$288,276
2		ADIT - CIAC			100.00%		100.00%	
3		Sub-total HTY	L1 + L2	288,276		288,276		288,276
4								
5	**FTY**	DIT - Distribution		($7,023)	100.00%	($7,023)	100.00%	($7,023)
6		DIT - CIAC			100.00%		100.00%	
7		Sub-total FTY	L5 + L6	(7,023)		(7,023)		(7,023)
8								
9	**FPFTY**	DIT - Distribution		($3,378)	100.00%	($3,378)	100.00%	($3,378)
10		DIT - CIAC			100.00%		100.00%	
11		Sub-total FPFTY	L9 + L10	(3,378)		(3,378)		(3,378)
12								
13		**Total**	L3 + L7 + L11	$277,875		$277,875		**$277,875**

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Line No.	Category	Description	Reference	(1) Pro Forma Adjusted at Present Rates	(2) Proposed Rate Increase	(3) Adjusted Amounts with Proposed Rate Increase
1	**Operating Revenues**	Residential		$1,616,574		$1,616,574
2		Residential - House Heating		358,919		358,919
3		C & I Small		417,041		417,041
4		C & I Large		237,936		237,936
5		Railroads & Railways		7,059		7,059
6		Street Lighting		22,848		22,848
7		Intercompany				
8		Transmission - All Classes		199,791		199,791
9		Forfeited Discounts		12,224	$1,406	13,630
10		Miscellaneous Service Revenues		3,684		3,684
11		Rent For Electric Property		22,580		22,580
12		Other Electric Revenues		9,534		9,534
13		Revenue Increase			$463,632	463,632
14		Total Operating Revenues	SUM L1 to L13	$2,908,189	$465,038	$3,373,227
15						
16	**Operating Expenses**	Power Supply		$1,003,713		$1,003,713
17		Transmission Expense		186,907		186,907
18		Distribution Expense		445,432		445,432
19		Customer Accounts Expense		162,107	$4,501	166,607
20		Customer Service and Information Expense		21,818		21,818
21		Sales Expense		422		422
22		Administrative & General		185,165	1,111	186,276
23		Sub-total O&M Expense	SUM L16 to L22	$2,005,564	$5,612	$2,011,176
24						
25		Depreciation & Amortization Expense		$336,287		$336,287
26		Amortization of Regulatory Expense		(448)		(448)
27		Taxes Other Than Income Taxes - Other		$192,333	$27,354	$219,687
28		Total Operating Expenses	SUM L23 to L27	$2,533,736	$32,966	$2,566,702
29						
30	**Net Operating Income - BIT**		L14 - L28	**$374,453**	**$432,072**	**$806,525**

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			(1)	(2)	(3)	(4)
Line No.	Category	Description	Reference	FPFTY Amount Pre Adjustments	Adjustments Sub-Total	Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential		$1,641,544	($24,970)	$1,616,574
2		Residential - House Heating		364,319	(5,400)	358,919
3		C & I Small		441,807	(24,766)	417,041
4		C & I Large		270,518	(32,581)	237,936
5		Railroads & Railways		8,121	(1,063)	7,059
6		Street Lighting		23,197	(349)	22,848
7		Intercompany				
8		Transmission - All Classes		199,791		199,791
9		Forfeited Discounts		12,224		12,224
10		Miscellaneous Service Revenues		3,684		3,684
11		Rent For Electric Property		22,580		22,580
12		Other Electric Revenues		9,534		9,534
13		Revenue Increase				
14		Total Operating Revenues	SUM L1 to L13	$2,997,318	($89,129)	$2,908,189
15						
16	**Operating Expenses**	Power Supply		$1,003,713		$1,003,713
17		Transmission Expense		186,907		186,907
18		Distribution Expense		427,846	$17,586	445,432
19		Customer Accounts Expense		147,808	14,298	162,107
20		Customer Service and Information Expense		103,916	(82,098)	21,818
21		Sales Expense		414	8	422
22		Administrative & General		178,632	6,533	185,165
23		Sub-total O&M Expense	SUM L16 to L22	$2,049,237	($43,673)	$2,005,564
24						
25		Depreciation & Amortization Expense		$318,997	$17,290	$336,287
26		Amortization of Regulatory Expense			(448)	(448)
27		Taxes Other Than Income Taxes - Other		197,517	(5,184)	192,333
28		Total Operating Expenses	SUM L23 to L27	$2,565,751	($32,015)	$2,533,736
29						
30	**Net Operating Income - BIT**		L14 - L28	**$431,567**	**($57,114)**	**$374,453**

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Line No.	Category	Description	Description	FPFTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Act 129 Lost Revenue	D-5D Energy Efficiency Program Cost Recovery	D-5E OPEN	D-5F Leap Year Adjustment	D-5G Weather Normalization
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Operating Revenues**	Residential	Elec Cost	$689,404							
2			Cust & Dist	952,140	1,321	(1,597)	(1,930)	(23,263)		498	
3			Sub-total Residential	$1,641,544	$1,321	($1,597)	($1,930)	($23,263)		$498	
4											
5		Residential - House Heating	Elec Cost	$180,937							
6			Cust & Dist	183,381	991	(195)	(404)	(5,941)		148	
7			Sub-total Residential - House Heating	$364,319	$991	($195)	($404)	($5,941)		$148	
8											
9		C & I Small	Elec Cost	$148,035							
10			Cust & Dist	293,772	567		(892)	(24,597)		155	
11			Sub-total C & I Small	$441,807	$567		($892)	($24,597)		$155	
12											
13		C & I Large	Elec Cost	$52,022							
14			Cust & Dist	218,495			(622)	(32,087)		127	
15			Sub-total C & I Large	$270,518			($622)	($32,087)		$127	
16											
17		Railroads & Railways	Cust & Dist	$8,121				($1,063)			
18			Sub-total Railroads & Railways	$8,121				($1,063)			
19											
20		Street Lighting	Elec Cost	$801							
21			Cust & Dist	22,396				(349)			
22			Sub-total Street Lighting	$23,197				($349)			
23											
24		Intercompany	Elec Cost								
25			Cust & Dist								
26			Sub-total Interdepartmental								
27											
28		Transmission - All Classes	Transmission - All Classes	$199,791							
29			Sub-total Transmission - All Classes	$199,791							
30											
31		Forfeited Discounts	Forfeited Discounts	$12,224							
32			Sub-total Forfeited Discounts	$12,224							
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues	$3,684							
35			Sub-total Miscellaneous Service Revenues	$3,684							
36											
37		Rent For Electric Property	Rent For Electric Property	$22,580							
38			Sub-total Rent For Electric Property	$22,580							
39											
40		Other Electric Revenues	Other Electric Revenues	$9,534							
41			Sub-total Other Electric Revenues	$9,534							
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**	**$2,997,318**	**$2,879**	**($1,791)**	**($3,846)**	**($87,299)**		**$929**	
47											
48	**Operating Expenses**	Power Supply	Purchased Power	$1,003,713							

Line No.	Category	Description	Description	FPFTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Act 129 Lost Revenue	D-5D Energy Efficiency Program Cost Recovery	D-5E OPEN	D-5F Leap Year Adjustment	D-5G Weather Normalization
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
49			Sub-total Power Supply	$1,003,713							
50											
51		Transmission Expense	Operation & Supervision								
52			Load Dispatching								
53			Scheduling, System Control & Dispatch	93,988							
54			Transmission Service Studies								
55			Generation Service Studies								
56			Reliability, Planning & Standard Development	92,919							
57			Station Expense								
58			Overhead Lines								
59			Underground Lines Expense								
60			Miscellaneous Expense								
61			Rents								
62			Maintenance of Structures								
63			Maintenance of Computer Hardware								
64			Maintenance of Computer Software								
65			Maintenance of Communication Equipment								
66			Maintenance of Station Equipment								
67			Maintenance of Overhead Lines								
68			Maintenance of Underground Lines								
69			Maintenance of Misc Transmission Plant								
70			Sub-total Transmission Expense	186,907							
71											
72		Distribution Expense	Operation & Supervision	$1,271							
73			Load Dispatching								
74			Station Expense	816							
75			Overhead Lines Expenses	17,513							
76			Underground Lines Expense	14,687							
77			Meter Expenses	7,801							
78			Customer Installations Expense	14,386							
79			Miscellaneous Expense	90,014							
80			Rents	3,658							
81			Maintenance of Structures	6,622							
82			Maintenance of Station Equipment	18,529							
83			Maintenance of Overhead Lines	189,290							
84			Maintenance of Underground Lines	38,602							
85			Maintenance of Line Transformers	2,378							
86			Maintenance of Street Lighting & Signal Systems	1,990							
87			Maintenance of Misc. Distribution	20,293							
88			Sub-total Distribution Expense	$427,846							
89											
90		Customer Accounts	Supervision								
91			Meter Reading	$976							
92			Customer Records and Collection	105,441							
93			Uncollectible Accounts	38,095							
94			Miscellaneous Customer Accounts Expenses.	3,295							
95			Sub-total Total Customer Accounts	$147,808							
96											

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Line No.	Category	Description	Description	FPFTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Act 129 Lost Revenue	D-5D Energy Efficiency Program Cost Recovery	D-5E OPEN	D-5F Leap Year Adjustment	D-5G Weather Normalization
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
97		Customer Service and Information	Customer Assistance	$101,517				($82,164)			
98			Informational & Instructional	1,407							
99			Miscellaneous Customer & Informational	992							
100			Sub-total Customer Service & Information	$103,916				($82,164)			
101											
102		Sales	Demonstrating & Selling	$414							
103			Miscellaneous Sales								
104			Sub-total Sales	$414							
105											
106		Administrative & General	Administrative and General Salaries	$29,889							
107			Office Supplies and Expenses	3,566							
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed	88,149							
110			Property Insurance	741							
111			Injuries & Damages	12,322							
112			Employee Pensions and Benefits	24,743							
113			Regulatory Commission Expenses	9,551							
114			Duplicate Charges-Credit	(1,092)							
115			Miscellaneous General Expenses	2,527							
116			Maintenance of General Plant	8,237							
117			Sub-total Administrative & General	$178,632							
118											
119			**Total O&M Expense**	$2,049,237				($82,164)			
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$318,997							
122			Sub-total Depreciation & Amortization Expense	$318,997							
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense								
125			Sub-total Amortization of Regulatory Expense								
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$197,517							
128			Sub-total Taxes Other Than Income Taxes - Other	$197,517							
129											
130			**Total Operating Expenses**	**$2,565,751**				**($82,164)**			
131											
132	**Net Operating Income Before Income Tax**			**$431,567**	**$2,879**	**($1,791)**	**($3,846)**	**($5,134)**		**$929**	

Line No.	Category	Description	Description	(9) D-6 Salary & Wages	(10) D-7 Rate Case Expense	(11) D-8 Adjustments for Employee Benefits	(12) D-9 Adjustments for Pension	(13) D-10 Uncollectible Accounts	(14) D-11 IIJA Reg Asset	(15) D-12 Customer Deposit Interest	(16) D-13 Storm
1	**Operating Revenues**	Residential	Elec Cost								
2			Cust & Dist								
3			Sub-total Residential								
4											
5		Residential - House Heating	Elec Cost								
6			Cust & Dist								
7			Sub-total Residential - House Heating								
8											
9		C & I Small	Elec Cost								
10			Cust & Dist								
11			Sub-total C & I Small								
12											
13		C & I Large	Elec Cost								
14			Cust & Dist								
15			Sub-total C & I Large								
16											
17		Railroads & Railways	Cust & Dist								
18			Sub-total Railroads & Railways								
19											
20		Street Lighting	Elec Cost								
21			Cust & Dist								
22			Sub-total Street Lighting								
23											
24		Intercompany	Elec Cost								
25			Cust & Dist								
26			Sub-total Interdepartmental								
27											
28		Transmission - All Classes	Transmission - All Classes								
29			Sub-total Transmission - All Classes								
30											
31		Forfeited Discounts	Forfeited Discounts								
32			Sub-total Forfeited Discounts								
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues								
35			Sub-total Miscellaneous Service Revenues								
36											
37		Rent For Electric Property	Rent For Electric Property								
38			Sub-total Rent For Electric Property								
39											
40		Other Electric Revenues	Other Electric Revenues								
41			Sub-total Other Electric Revenues								
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**								
47											
48	**Operating Expenses**	Power Supply	Purchased Power								

Line No.	Category	Description	Description	(9) D-6 Salary & Wages	(10) D-7 Rate Case Expense	(11) D-8 Adjustments for Employee Benefits	(12) D-9 Adjustments for Pension	(13) D-10 Uncollectible Accounts	(14) D-11 IIJA Reg Asset	(15) D-12 Customer Deposit Interest	(16) D-13 Storm
49			Sub-total Power Supply								
50											
51		Transmission Expense	Operation & Supervision								
52			Load Dispatching								
53			Scheduling, System Control & Dispatch								
54			Transmission Service Studies								
55			Generation Service Studies								
56			Reliability, Planning & Standard Development								
57			Station Expense								
58			Overhead Lines								
59			Underground Lines Expense								
60			Miscellaneous Expense								
61			Rents								
62			Maintenance of Structures								
63			Maintenance of Computer Hardware								
64			Maintenance of Computer Software								
65			Maintenance of Communication Equipment								
66			Maintenance of Station Equipment								
67			Maintenance of Overhead Lines								
68			Maintenance of Underground Lines								
69			Maintenance of Misc Transmission Plant								
70			Sub-total Transmission Expense								
71											
72		Distribution Expense	Operation & Supervision	$35							
73			Load Dispatching								
74			Station Expense	2							
75			Overhead Lines Expenses	106							
76			Underground Lines Expense	87							
77			Meter Expenses	90							
78			Customer Installations Expense	219							
79			Miscellaneous Expense	247							
80			Rents								
81			Maintenance of Structures	46							
82			Maintenance of Station Equipment	303							
83			Maintenance of Overhead Lines	1,492							14,213
84			Maintenance of Underground Lines	581							
85			Maintenance of Line Transformers	17							
86			Maintenance of Street Lighting & Signal Systems	4							
87			Maintenance of Misc. Distribution	144							
88			Sub-total Distribution Expense	$3,373							$14,213
89											
90		Customer Accounts	Supervision								
91			Meter Reading	0							
92			Customer Records and Collection	1,265							
93			Uncollectible Accounts				9,477				
94			Miscellaneous Customer Accounts Expenses.	27					3,572		
95			Sub-total Total Customer Accounts	$1,292			$9,477		$3,572		
96											

Line No.	Category	Description	Description	(9) D-6 Salary & Wages	(10) D-7 Rate Case Expense	(11) D-8 Adjustments for Employee Benefits	(12) D-9 Adjustments for Pension	(13) D-10 Uncollectible Accounts	(14) D-11 IIJA Reg Asset	(15) D-12 Customer Deposit Interest	(16) D-13 Storm
97		Customer Service and Information	Customer Assistance	$58							
98			Informational & Instructional								
99			Miscellaneous Customer & Informational	7							
100			Sub-total Customer Service & Information	$66							
101											
102		Sales	Demonstrating & Selling	$8							
103			Miscellaneous Sales								
104			Sub-total Sales	$8							
105											
106		Administrative & General	Administrative and General Salaries	$886							
107			Office Supplies and Expenses								
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed								
110			Property Insurance								
111			Injuries & Damages	62							
112			Employee Pensions and Benefits	1		64	3,272				
113			Regulatory Commission Expenses		1,200						
114			Duplicate Charges-Credit								
115			Miscellaneous General Expenses	2							
116			Maintenance of General Plant	46							
117			Sub-total Administrative & General	$997	$1,200	$64	$3,272				
118											
119			**Total O&M Expense**	$5,736	$1,200	$64	$3,272	$9,477		$3,572	$14,213
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense								
122			Sub-total Depreciation & Amortization Expense								
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense						($448)		
125			Sub-total Amortization of Regulatory Expense						($448)		
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other								
128			Sub-total Taxes Other Than Income Taxes - Other								
129											
130			**Total Operating Expenses**	**$5,736**	**$1,200**	**$64**	**$3,272**	**$9,477**	**($448)**	**$3,572**	**$14,213**
131											
132	**Net Operating Income Before Income Tax**			**($5,736)**	**($1,200)**	**($64)**	**($3,272)**	**($9,477)**	**$448**	**($3,572)**	**($14,213)**

				(17)	(18)	(19)	(20)	(21)	(22)
Line No.	Category	Description	Description	D-14 Other Adjustments	D-15 OPEN	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Elec Cost						$689,404
2			Cust & Dist					(24,970)	927,169
3			Sub-total Residential					($24,970)	$1,616,574
4									
5		Residential - House Heating	Elec Cost						$180,937
6			Cust & Dist					(5,400)	177,981
7			Sub-total Residential - House Heating					($5,400)	$358,919
8									
9		C & I Small	Elec Cost						$148,035
10			Cust & Dist					(24,766)	269,006
11			Sub-total C & I Small					($24,766)	$417,041
12									
13		C & I Large	Elec Cost						$52,022
14			Cust & Dist					(32,581)	185,914
15			Sub-total C & I Large					($32,581)	$237,936
16									
17		Railroads & Railways	Cust & Dist					($1,063)	$7,059
18			Sub-total Railroads & Railways					($1,063)	$7,059
19									
20		Street Lighting	Elec Cost						$801
21			Cust & Dist					(349)	22,047
22			Sub-total Street Lighting					($349)	$22,848
23									
24		Intercompany	Elec Cost						
25			Cust & Dist						
26			Sub-total Interdepartmental						
27									
28		Transmission - All Classes	Transmission - All Classes						$199,791
29			Sub-total Transmission - All Classes						$199,791
30									
31		Forfeited Discounts	Forfeited Discounts						$12,224
32			Sub-total Forfeited Discounts						$12,224
33									
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues						$3,684
35			Sub-total Miscellaneous Service Revenues						$3,684
36									
37		Rent For Electric Property	Rent For Electric Property						$22,580
38			Sub-total Rent For Electric Property						$22,580
39									
40		Other Electric Revenues	Other Electric Revenues						$9,534
41			Sub-total Other Electric Revenues						$9,534
42									
43		Revenue Increase	Revenue Increase						
44			Sub-total Revenue Increase						
45									
46			**Total Operating Revenues**					**($89,129)**	**$2,908,189**
47									
48	**Operating Expenses**	Power Supply	Purchased Power						$1,003,713

Line No.	Category	Description	Description	(17) D-14 Other Adjustments	(18) D-15 OPEN	(19) D-16 Taxes Other Than Income	(20) D-17 Depreciation Annualization	(21) Adjustments Sub-total	(22) Pro Forma Adjusted at Present Rates
49			Sub-total Power Supply						$1,003,713
50									
51		Transmission Expense	Operation & Supervision						
52			Load Dispatching						
53			Scheduling, System Control & Dispatch						93,988
54			Transmission Service Studies						
55			Generation Service Studies						
56			Reliability, Planning & Standard Development						92,919
57			Station Expense						
58			Overhead Lines						
59			Underground Lines Expense						
60			Miscellaneous Expense						
61			Rents						
62			Maintenance of Structures						
63			Maintenance of Computer Hardware						
64			Maintenance of Computer Software						
65			Maintenance of Communication Equipment						
66			Maintenance of Station Equipment						
67			Maintenance of Overhead Lines						
68			Maintenance of Underground Lines						
69			Maintenance of Misc Transmission Plant						
70			Sub-total Transmission Expense						186,907
71									
72		Distribution Expense	Operation & Supervision					$35	$1,306
73			Load Dispatching						
74			Station Expense					2	817
75			Overhead Lines Expenses					106	17,619
76			Underground Lines Expense					87	14,774
77			Meter Expenses					90	7,891
78			Customer Installations Expense					219	14,605
79			Miscellaneous Expense					247	90,261
80			Rents						3,658
81			Maintenance of Structures					46	6,667
82			Maintenance of Station Equipment					303	18,832
83			Maintenance of Overhead Lines					15,705	204,995
84			Maintenance of Underground Lines					581	39,183
85			Maintenance of Line Transformers					17	2,395
86			Maintenance of Street Lighting & Signal Systems					4	1,993
87			Maintenance of Misc. Distribution					144	20,437
88			Sub-total Distribution Expense					$17,586	$445,432
89									
90		Customer Accounts	Supervision						
91			Meter Reading					$0	$976
92			Customer Records and Collection					1,265	106,706
93			Uncollectible Accounts					9,477	47,572
94			Miscellaneous Customer Accounts Expenses.	(43)				3,556	6,852
95			Sub-total Total Customer Accounts	($43)				$14,298	$162,107
96									

Line No.	Category	Description	Description	(17) D-14 Other Adjustments	(18) D-15 OPEN	(19) D-16 Taxes Other Than Income	(20) D-17 Depreciation Annualization	(21) Adjustments Sub-total	(22) Pro Forma Adjusted at Present Rates
97		Customer Service and Information	Customer Assistance					($82,106)	$19,411
98			Informational & Instructional						1,407
99			Miscellaneous Customer & Informational					7	1,000
100			Sub-total Customer Service & Information					($82,098)	$21,818
101									
102		Sales	Demonstrating & Selling					$8	$422
103			Miscellaneous Sales						
104			Sub-total Sales					$8	$422
105									
106		Administrative & General	Administrative and General Salaries					$886	$30,775
107			Office Supplies and Expenses						3,566
108			Administrative Expenses Transferred-Credit						
109			Outside Service Employed						88,149
110			Property Insurance						741
111			Injuries & Damages					62	12,384
112			Employee Pensions and Benefits					3,337	28,080
113			Regulatory Commission Expenses					1,200	10,751
114			Duplicate Charges-Credit						(1,092)
115			Miscellaneous General Expenses	1,000				1,002	3,529
116			Maintenance of General Plant					46	8,283
117			Sub-total Administrative & General	$1,000				$6,533	$185,165
118									
119			**Total O&M Expense**	$957				($43,673)	$2,005,564
120									
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense				$17,290	$17,290	$336,287
122			Sub-total Depreciation & Amortization Expense				$17,290	$17,290	$336,287
123									
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense					($448)	($448)
125			Sub-total Amortization of Regulatory Expense					($448)	($448)
126									
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other			($5,184)		($5,184)	$192,333
128			Sub-total Taxes Other Than Income Taxes - Other			($5,184)		($5,184)	$192,333
129									
130			**Total Operating Expenses**	**$957**		**($5,184)**	**$17,290**	**($32,015)**	**$2,533,736**
131									
132	**Net Operating Income Before Income Tax**			**($957)**		**$5,184**	**($17,290)**	**($57,114)**	**$374,453**

Line No.	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5D Energy Efficiency Program Expense	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 IIJA Reg Asset
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.	$1,003,713							
2			Sub-total Power Supply	$1,003,713							
3											
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision								
5			561.0 Load Dispatching								
6			561.4 Scheduling, System Control & Dispatch	93,988							
7			561.6 Transmission Service Studies								
8			561.7 Generation Service Studies								
9			561.8 Reliability, Planning & Standard Development	92,919							
10			562.0 Station Expense								
11			563.0 Overhead Lines								
12			564.0 Underground Lines Expense								
13			566.0 Miscellaneous Expense								
14			567.0 Rents								
15			Sub-total Transmission Operations	186,907							
16											
17		**Transmission Maintenance**	569.0 Maintenance of Structures								
18			569.1 Maintenance of Computer Hardware								
19			569.2 Maintenance of Computer Software								
20			569.3 Maintenance of Communication Equipment								
21			570.0 Maintenance of Station Equipment								
22			571.0 Maintenance of Overhead Lines								
23			572.0 Maintenance of Underground Lines								
24			573.0 Maintenance of Misc Transmission Plant								
25			Sub-total Transmission Maintenance								
26											
27			Sub-total TRANSMISSION EXPENSE	186,907							
28											
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision	$1,271	$35						
30			581.0 Load Dispatching								
31			582.0 Station Expense	816	2						
32			583.0 Overhead Lines Expenses	17,513	106						
33			584.0 Underground Lines Expense	14,687	87						
34			586.0 Meter Expenses	7,801	90						
35			587.0 Customer Installations Expense	14,386	219						
36			588.0 Miscellaneous Expense	90,014	247						
37			589.0 Rents	3,658							
38			Sub-total Distribution Operations	$150,143	$787						
39											
40		**Distribution Maintenance**	591.0 Maintenance of Structures	$6,622	$46						
41			592.0 Maintenance of Station Equipment	18,529	303						
42			593.0 Maintenance of Overhead Lines	189,290	1,492						
43			594.0 Maintenance of Underground Lines	38,602	581						
44			595.0 Maintenance of Line Transformers	2,378	17						
45			596.0 Maintenance of Street Lighting & Signal Systems	1,990	4						
46			598.0 Maintenance of Misc. Distribution	20,293	144						
47			Sub-total Distribution Maintenance	$277,703	$2,587						
48											

Line No.	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5D Energy Efficiency Program Expense	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 IIJA Reg Asset
49			Sub-total DISTRIBUTION EXPENSE	$427,846		$3,373					
50											
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision								
52			902.0 Meter Reading	$976		0					
53			903.0 Customer Records and Collection	105,441		1,265					
54			904.0 Uncollectible Accounts.	38,095						9,477	
55			905.0 Miscellaneous Customer Accounts Expenses.	3,295		27					
56			Sub-total Customer Accounts	$147,808		$1,292				$9,477	
57											
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance	$101,517	($82,164)	$58					
59			909.0 Informational & Instructional	1,407							
60			910.0 Miscellaneous Customer & Informational	992		7					
61			Sub-total Customer Service & Information	$103,916	($82,164)	$66					
62											
63	**SALES**	**Sales**	912.0 Demonstrating & Selling	$414		$8					
64			916.0 Miscellaneous Sales								
65			Sub-total Sales	$414		$8					
66											
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries	$29,889		$886					
68			921.0 Office Supplies and Expenses	3,566							
69			922.0 Administrative Expenses Transferred-Credit								
70			923.0 Outside Service Employed	88,149							
71			924.0 Property Insurance	741							
72			925.0 Injuries & Damages	12,322		62					
73			926.0 Employee Pensions and Benefits	24,743		1		64	3,272		
74			928.0 Regulatory Commission Expenses	9,551			1,200				
75			929.0 Duplicate Charges-Credit	(1,092)							
76			930.2 Miscellaneous General Expenses	2,527		2					
77			Sub-total A&G Operations	$170,395		$951	$1,200	$64	$3,272		
78											
79		A&G Maintenance	935.0 Maintenance of General Plant	$8,237		$46					
80											
81			Sub-total ADMINISTRATION & GENERAL	$178,632		$997	$1,200	$64	$3,272		
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$268,901							
84			404.0 Amort. Of Limited-Term Electric Plant.	50,096							
85			Sub-total Depreciation & Amortization Expense	$318,997							
86											
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.								($448)
88			Sub-total Amortization of Regulatory Expense								($448)
89											
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$197,517							
91			Sub-total Taxes Other Than Income Taxes - Other	$197,517							
92											
93			**Total**	**$2,565,751**	**($82,164)**	**$5,736**	**$1,200**	**$64**	**$3,272**	**$9,477**	**($448)**

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 Storm	(11) D-14 Other Adjustments	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.								$1,003,713
2			Sub-total Power Supply								$1,003,713
3											
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision								
5			561.0 Load Dispatching								
6			561.4 Scheduling, System Control & Dispatch								93,988
7			561.6 Transmission Service Studies								
8			561.7 Generation Service Studies								
9			561.8 Reliability, Planning & Standard Development								92,919
10			562.0 Station Expense								
11			563.0 Overhead Lines								
12			564.0 Underground Lines Expense								
13			566.0 Miscellaneous Expense								
14			567.0 Rents								
15			Sub-total Transmission Operations								186,907
16											
17		**Transmission Maintenance**	569.0 Maintenance of Structures								
18			569.1 Maintenance of Computer Hardware								
19			569.2 Maintenance of Computer Software								
20			569.3 Maintenance of Communication Equipment								
21			570.0 Maintenance of Station Equipment								
22			571.0 Maintenance of Overhead Lines								
23			572.0 Maintenance of Underground Lines								
24			573.0 Maintenance of Misc Transmission Plant								
25			Sub-total Transmission Maintenance								
26											
27			Sub-total TRANSMISSION EXPENSE								186,907
28											
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision							$35	$1,306
30			581.0 Load Dispatching								
31			582.0 Station Expense							$2	$817
32			583.0 Overhead Lines Expenses							$106	$17,619
33			584.0 Underground Lines Expense							$87	$14,774
34			586.0 Meter Expenses							$90	$7,891
35			587.0 Customer Installations Expense							$219	$14,605
36			588.0 Miscellaneous Expense							$247	$90,261
37			589.0 Rents								$3,658
38			Sub-total Distribution Operations							$787	$150,930
39											
40		**Distribution Maintenance**	591.0 Maintenance of Structures							$46	$6,667
41			592.0 Maintenance of Station Equipment							303	18,832
42			593.0 Maintenance of Overhead Lines		14,213					15,705	204,995
43			594.0 Maintenance of Underground Lines							581	39,183
44			595.0 Maintenance of Line Transformers							17	2,395
45			596.0 Maintenance of Street Lighting & Signal Systems							4	1,993
46			598.0 Maintenance of Misc. Distribution							144	20,437
47			Sub-total Distribution Maintenance		$14,213					$16,800	$294,502
48											

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 Storm	(11) D-14 Other Adjustments	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
49			Sub-total DISTRIBUTION EXPENSE		$14,213					$17,586	$445,432
50											
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision								
52			902.0 Meter Reading							$0	$976
53			903.0 Customer Records and Collection							$1,265	106,706
54			904.0 Uncollectible Accounts.							9,477	47,572
55			905.0 Miscellaneous Customer Accounts Expenses.	3,572		(43)				3,556	6,852
56			Sub-total Customer Accounts	$3,572		($43)				$14,298	$162,107
57											
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance							($82,106)	$19,411
59			909.0 Informational & Instructional								1,407
60			910.0 Miscellaneous Customer & Informational							7	1,000
61			Sub-total Customer Service & Information							($82,098)	$21,818
62											
63	**SALES**	**Sales**	912.0 Demonstrating & Selling							$8	$422
64			916.0 Miscellaneous Sales								
65			Sub-total Sales							$8	$422
66											
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries							$886	$30,775
68			921.0 Office Supplies and Expenses								3,566
69			922.0 Administrative Expenses Transferred-Credit								
70			923.0 Outside Service Employed								88,149
71			924.0 Property Insurance								741
72			925.0 Injuries & Damages							62	12,384
73			926.0 Employee Pensions and Benefits							3,337	28,080
74			928.0 Regulatory Commission Expenses							1,200	10,751
75			929.0 Duplicate Charges-Credit								(1,092)
76			930.2 Miscellaneous General Expenses			1,000				1,002	3,529
77			Sub-total A&G Operations			$1,000				$6,487	$176,882
78											
79		A&G Maintenance	935.0 Maintenance of General Plant							$46	$8,283
80											
81			Sub-total ADMINISTRATION & GENERAL			$1,000				$6,533	$185,165
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$15,117	$15,117	$284,018
84			404.0 Amort. Of Limited-Term Electric Plant.						2,172	2,172	52,269
85			Sub-total Depreciation & Amortization Expense						$17,290	$17,290	$336,287
86											
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.							($448)	($448)
88			Sub-total Amortization of Regulatory Expense							($448)	($448)
89											
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					($5,184)		($5,184)	$192,333
91			Sub-total Taxes Other Than Income Taxes - Other					($5,184)		($5,184)	$192,333
92											
93			**Total**	**$3,572**	**$14,213**	**$957**		**($5,184)**	**$17,290**	**($32,015)**	**$2,533,736**

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Line No.	Category	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act - 129 Lost Revenue Due To Load Reduction	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E OPEN	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization	(9) Adjustments Sub-total	(10) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	440.0	$952,140	$1,321	($1,597)	($1,930)	($23,263)		$498		($24,970)	$927,169
2			Residential - House Heating	440.1	183,381	991	(195)	(404)	(5,941)		148		(5,400)	177,981
3			C & I Small	442.0	293,772	567		(892)	(24,597)		155		(24,766)	269,006
4			C & I Large	442.1	218,495			(622)	(32,087)		127		(32,581)	185,914
5			Railroads & Railways	446.0	8,121				(1,063)				(1,063)	7,059
6			Street Lighting	444.0	22,396				(349)				(349)	22,047
7			Intercompany	448.0										
8			Transmission - All Classes		199,791									199,791
9			Sub-total - Customer & Distribution Revenues		$1,878,096	$2,879	($1,791)	($3,846)	($87,299)		$929		($89,129)	$1,788,967
10														
11		**Electric Cost Revenue**	Residential	440.0	$689,404									$689,404
12			Residential - House Heating	440.1	180,937									180,937
13			C & I Small	442.0	148,035									148,035
14			C & I Large	442.1	52,022									52,022
15			Railroads & Railways	446.0										
16			Street Lighting	444.0	801									801
17			Intercompany	448.0										
18			Sub-total - Electric Cost Revenue		$1,071,200									$1,071,200
19														
20			**Total OPERATING REVENUE**		$2,949,296	$2,879	($1,791)	($3,846)	($87,299)		$929		($89,129)	$2,860,167
21														
22	*OTHER REVENUE*	**Other Electric Revenue**	Rent For Electric Property	454.0	$22,580									$22,580
23			Other Electric Revenues	456.0	9,534									9,534
24			Transmission of Electricity for Others	456.1										
25			Sub-total - Other electric Revenue		$32,114									$32,114
26														
27		**Other Operating Revenue**	Forfeited Discounts	450.0	$12,224									$12,224
28			Miscellaneous Service Revenues	451.0	3,684									3,684
29			Sub-total - Other Operating Revenue		$15,908									$15,908
30														
31			**Total OTHER REVENUE**		$48,022									$48,022
32														
33			**Total REVENUE**		**$2,997,318**	**$2,879**	**($1,791)**	**($3,846)**	**($87,299)**		**$929**		**($89,129)**	**$2,908,189**

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Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales	(3) 442001: C&I Sales-Small	(4) 442002: C&I Sales-Large	(5) C & I Total
1	Total FPFTY Revenues		$1,754,162	$393,755	$475,391	$293,645	$769,035
2	Commodity Billings in Revenues		(802,022)	(210,374)	(181,619)	(75,149)	(256,768)
3	Weather Adjustment						
4	Total Reconcilable Surcharge in Revenues		(16,861)	(4,269)	(20,111)	(23,703)	(43,814)
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$935,279	$179,112	$273,661	$194,792	$468,453
6							
7	Average Monthly Customers in FPFTY		1,338,774	204,336	156,564	3,110	159,674
8							
9	Average Annual Margin Per Customer	L5 / L7	$0.699	$0.877	$1.748	$62.634	$2.934
10							
11	Number of Customers at end of FPFTY		1,340,665	205,467	156,888	3,110	159,998
12							
13	Increase in Customers during FPFTY	L11 - L7	1,891	1,131	324		324
14							
15	**Annualization of Revenue**	L9 * L13	**$1,321**	**$991**	**$567**		**$567**

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		(1)	(2)	(3)
Line No.	Description	Reference	440000: Residental Sales	440001: Residental Heating Sales
1	CAP Discount		($129,368)	($15,786)
2				
3				
4	**ANNUALIZATION TO YEAR END CUSTOMERS**			
5				
6	Annual CAP Customers		1,395,081	175,423
7	Average Monthly CAP Customers		116,257	14,619
8	Average Annual CAP Discount Per Customer	L1 / L7	($1.113)	($1.080)
9				
10	CAP Customers at End of FPFTY		117,860	14,820
11	Increase of CAP Customers	L10 - L7	1,603	201
12				
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	($1,784)	($218)
14	Write-Offs & Working Capital Factor		10.5%	10.5%
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	$187	$23
16				
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**($1,597)**	**($195)**

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	(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	2025 Revenue Loss	2026 Revenue Loss	2026 Revenue Loss Over 2025	Recovery of Incremental Revenue Loss
1	**Revenue Impact in 2025 - Included in FPFTY Year Budget**					
2	Residential		($3,767)			
3	Residential Heaing		(788)			
4	Small C&I		(2,276)			
5	Large C&I		(1,583)			
6	Total	SUM L2 to L5	($8,413)			
7						
8	**Target Revenue Impact in 2026**					
9	Residential			($7,626)		
10	Residential Heaing			(1,595)		
11	Small C&I			(4,060)		
12	Large C&I			(2,826)		
13	Total	SUM L9 to L12		($16,106)		
14						
15	**Incremental Revenue Impact Over FPFTY Budget**					
16	Residential	L9 - L2			($3,859)	
17	Residential Heaing	L10 - L3			(807)	
18	Small C&I	L11 - L4			(1,783)	
19	Large C&I	L12 - L5			(1,244)	
20	Total	SUM L16 to L19			($7,693)	
21						
22	**Average Annual Incremental Revenue Not in FPFTY Budget**					
23	Residential	L16 / 2				($1,930)
24	Residential Heaing	L17 / 2				(404)
25	Small C&I	L18 / 2				(892)
26	Large C&I	L19 / 2				(622)
27	**Total**	SUM L23 to L26				**($3,846)**

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Line No.	Account / Description	(1) Reference	(2) Total
1	440000: Residential Sales		($23,263)
2	440001: Residential Heating Sales		(5,941)
3	442001: C&I Sales-Small		(24,597)
4	442002: C&I Sales-Large		(32,087)
5	444000: Public Street/Highway Lighting		(349)
6	446000: Sales-Railroad/Railway		(1,063)
7	**Reduction in Retail Revenue**	SUM L1 to L6	**($87,299)**
8			
9	O&M Expense		($82,164)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Reference	440000: Residental Sales	440001: Residental Heating Sales	442001: C&I Sales-Small	442002: C&I Sales-Large	C & I Total
1	Revenue in February of FPFTY		$55,822	$16,572	$17,409	$14,220	$31,629
2	Days in February of FPFTY		28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	$1,994	$592	$622	$508	
4	Average Days in February		28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	
6							
7	**Leap Year Adjustment**	L3 * L5	**$498**	**$148**	**$155**	**$127**	**$282**

(1)

Line No.	Account	Total
1	Residental Sales	
2	Residental Heating Sales	
3	C&I Sales-Small	
4	C&I Sales-Large	
5		
6	**Total**	

Line No.	Description	Reference	(1) Union	(2) Non-Union
1	Number of Employees @ HTY - Union/Non-Union		1,044	1,168
2	Number of Employees @ HTY - Total		2,213	2,213
3	Percentage of Employees @ HTY	L1 / L2	47.20%	52.80%
4	Distribution of Budget S&W Expense		$79,266	$88,656
5				
6	**Annualize March 1 Wage Increase for FPFTY**			
7	Number of Months TY			2
8	Rate for Increase TY		2.50%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$443
10		L4 + L9	$79,266	$89,099
11				
12	**Annualize January 1 and March 1, 2026 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		2.50%	3.00%
15	Total Adjustment	(L10 * L13 * L14) / 12	$1,982	$2,673
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$81,248**	**$91,772**

		(1)	(2)
Line No.	Description	Reference	Amount
1	Distribution of S&W Expense		$167,922
2			
3	Annualized S&W Including Wage Increases		$173,020
4			
5	**Adjustment for Union Contract**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		77.49%
8	Union Contract Payment for Utility	L6 * L7	$1,010
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$168
11			
12	Adjusted S&W for Employees in FPFTY	L3 + L10	$173,189
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ FPFTY		2,373
16	Average Number of Employees in FPFTY - Total		2,366
17	Annualization for Number of Employees	L15 - L16	6
18	Annual S&W per Employee	L12 / L16	$73
19	Annualization of S&W for New Employees	L17 * L18	$470
20			
21	Pro Forma FPFTY S&W	L12 + L19	$173,658
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$5,736**
24			
25	S&W Pro Forma Factor	L23 / L1	3.42%

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
1	**Operations**	**Power Supply Expenses**	555.0 Purchased Power.			
2			Sub-total Power Supply Expenses			
3						
4		**Transmission Expense**	560.0 Operation & Supervision			
5			561.0 Load Dispatching			
6			561.4 Scheduling, System Control & Dispatch			
7			561.6 Transmission Service Studies			
8			561.7 Generation Service Studies			
9			561.8 Reliability, Planning & Standard Development			
10			562.0 Station Expense			
11			563.0 Overhead Lines			
12			564.0 Underground Lines Expense			
13			566.0 Miscellaneous Expense			
14			567.0 Rents			
15			569.0 Maintenance of Structures			
16			569.1 Maintenance of Computer Hardware			
17			569.2 Maintenance of Computer Software			
18			569.3 Maintenance of Communication Equipment			
19			570.0 Maintenance of Station Equipment			
20			571.0 Maintenance of Overhead Lines			
21			572.0 Maintenance of Underground Lines			
22			573.0 Maintenance of Misc Transmission Plant			
23			Sub-total Transmission Expense			
24						
25		**Distribution Expense**	580.0 Operation & Supervision	$1,029	$35	$1,065
26			581.0 Load Dispatching			
27			582.0 Station Expense	53	2	55
28			583.0 Overhead Lines Expenses	3,114	106	3,221
29			584.0 Underground Lines Expense	2,554	87	2,641
30			586.0 Meter Expenses	2,646	90	2,737
31			587.0 Customer Installations Expense	6,411	219	6,630
32			588.0 Miscellaneous Expense	7,221	247	7,468
33			589.0 Rents			
34			591.0 Maintenance of Structures	1,341	46	1,387
35			592.0 Maintenance of Station Equipment	8,863	303	9,165
36			593.0 Maintenance of Overhead Lines	43,678	1,492	45,170
37			594.0 Maintenance of Underground Lines	17,015	581	17,596
38			595.0 Maintenance of Line Transformers	496	17	513
39			596.0 Maintenance of Street Lighting & Signal Systems	103	4	107
40			598.0 Maintenance of Misc. Distribution	4,228	144	4,372
41			Sub-total Distribution Operations	$98,752	$3,373	$102,126
42						

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
43	**Customer Accounts**		901.0 Supervision			
44			902.0 Meter Reading	$0	$0	$0
45			903.0 Customer Records and Collection	37,027	1,265	38,292
46			904.0 Uncollectible Accounts.			
47			905.0 Miscellaneous Customer Accounts Expenses.	790	27	817
48			Sub-total Customer Accounts	$37,817	$1,292	$39,109
49						
50	**Customer Service & Information**		908.0 Customer Assistance	$1,710	$58	$1,768
51			909.0 Informational & Instructional			
52			910.0 Miscellaneous Customer & Informational	219	7	226
53			Sub-total Customer Service & Information	$1,928	$66	$1,994
54						
55	**Sales**		912.0 Demonstrating & Selling	$228	$8	$236
56			916.0 Miscellaneous Sales			
57			Sub-total Sales	$228	$8	$236
58						
59	**Administration & General**		920.0 Administrative and General Salaries	$25,929	$886	$26,815
60			921.0 Office Supplies and Expenses			
61			922.0 Administrative Expenses Transferred-Credit			
62			923.0 Outside Service Employed			
63			924.0 Property Insurance			
64			925.0 Injuries & Damages	1,824	62	1,887
65			926.0 Employee Pensions and Benefits	35	1	36
66			928.0 Regulatory Commission Expenses			
67			929.0 Duplicate Charges-Credit			
68			930.2 Miscellaneous General Expenses	62	2	64
69			935.0 Maintenance of General Plant	1,345	46	1,391
70			Sub-total Administration & General	$29,195	$997	$30,193
71						
72			**Total**	**$167,922**	**$5,736**	**$173,658**
73						
74	**Percent Increas**		**Percent Increase**			3.42%

Line No.	Description	Reference	(1) Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$3
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		6
4	Total Recorded Up To Period End of HTY	SUM L2 to L3	$9
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$1,997
8	Materials, IT Costs, Travel, Copies, etc.		394
9	Total Expenditure Expected in FTY	SUM L7 to L8	$2,391
10			
11	Total Rate Case Expense	L4 + L9	$2,400
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,200
15			
16	Annual Amortization Amount Included in Budget		
17	**Pro Forma Adjustment for Annual Amortization**	L14 - L16	**$1,200**

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Line No.	Description	Reference	(1) Jurisdictional Amount
1	**Number of Employees**		
2	Employees at Eleven Months Prior		2,359
3	Employees at Ten Months Prior		2,363
4	Employees at Nine Months Prior		2,358
5	Employees at Eight Months Prior		2,358
6	Employees at Seven Months Prior		2,360
7	Employees at Six Months Prior		2,363
8	Employees at Five Months Prior		2,364
9	Employees at Four Months Prior		2,366
10	Employees at Three Months Prior		2,377
11	Employees at Two Months Prior		2,377
12	Employees at One Month Prior		2,379
13	Employees at End of FPFTY		2,373
14			
15	Average Monthly Employees in FPFTY	AVERAGE L2 to L13	2,366
16	Additional Employees in FPFTY		6
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$23,617
20	Number of Employees for Budget		2,366
21	Budget Expense Per Employee	L19 / L20	$10
22	Additional Employees for Annualization	L16	6
23	**Total Benefits Pro Forma Adjustment**	L21 * L22	**$64**

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		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	Pension Contribution for Four Years Prior to FPFTY		$17,267
2	Pension Contribution for Three Years Prior to FPFTY		15,222
3	Pension Contribution for Two Years Prior to FPFTY		1,408
4	Pension Contribution for One Year Prior to FPFTY		2,878
5	Pension Contribution for FPFTY		3,300
6			
7	Average Pension Contribution	Average L1 to L5	$8,015
8			
9	Percent to Electric Distribution		77.49%
10	Total Amount to Electric Distribution	L7 * L9	$6,211
11	Pension Capitalization Factor		48.21%
12	Pension Contribution To Be Capitalized	L10 * L11	2,994
13	Pension Contribution To Be Expensed	L10 - L12	$3,216
14	FPFTY Distribution Pension Expense		(56)
15	**Additional Pension Expense**	L13 - L14	**$3,272**

Line No.	Description	Reference	Reference	Charge Off Amounts	InPA Charge Off Amounts	Net Charge Off Amounts	Billed Revenue	Percent	PPA	Totals
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$29,237	$2,395	$26,842	$3,365,014	0.7977%		
2		One Year Prior to HTY		37,820	(28)	37,848	3,810,090	0.9934%		
3		HTY		42,650	17	42,632	3,880,008	1.0988%		
4		Three Year Average	SUM L1 to L3 / 3	$36,569	$795	$35,774	$3,685,037	0.9708%		
5										
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	FPFTY					$2,860,167			
7										
8	Tariff Revenue - Non Shopping Revenue	FPFTY	L6				$2,860,167			
9										
10	Tariff Revenue - Shopping Revenue	FPFTY					1,082,504			
11										
12	Tariff Revenue - Including Shopping Revenue	FPFTY	L8 + L10				$3,942,671			
13										
14	**Total General Pro Forma Uncollectible Accounts**		Col 7 L4 * L12							$38,275
15										
16	**NET PPA UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY						$6,462		
17		One Year Prior to HTY						9,314		
18		HTY						12,116		
19										
20	**Three Year Average PPA**		SUM L16 to L18 / 3							$9,297
21										
22	**Total Pro Forma Uncollectible Accounts**		L14 + L20							$47,572
23										
24	Uncollectible Accounts (904)	FPFTY								$38,095
25										
26	**Total Pro Forma Adjustment for Uncollectible Accounts**		L22 - L24							**$9,477**

		(1)	(2)
Line No.	Description	Reference	Total
1	Actual IIJA Related Incremental Costs in 2022 and 2023		$411
2	Amortization Years		2
3	Pro Forma Adjustment Amount	L1 / L2	$205
4	Remove Estimated IIJA Related Incremental Costs in 2025		(653)
5	Total Pro Forma Adjustment Amount	L3 + L4	($448)

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Line No.	Description	Description	Reference	Interest Rate	Deposit Amount	Interest on Deposit Amount	Interest Sub Total	Interest Total
			(1)	(2)	(3)	(4)	(5)	(6)
1	**Residential**	Monthly Interest Rate		0.667%				
2								
3	January				18,976	127		
4	February				19,166	128		
5	March				19,446	130		
6	April				20,077	134		
7	May				20,877	139		
8	June				21,538	144		
9	July				22,060	147		
10	August				22,549	150		
11	September				22,772	152		
12	October				23,058	154		
13	November				23,276	155		
14	December				23,215	155		
15	**Total Residential**		SUM Col 4 L3 to L14				$1,713	
16								
17	**Non-Residential**	Monthly Interest Rate		0.425%				
18								
19	January				32,487	138		
20	February				33,197	141		
21	March				33,844	144		
22	April				34,307	146		
23	May				35,117	149		
24	June				35,642	151		
25	July				36,988	157		
26	August				38,022	162		
27	September				38,782	165		
28	October				39,358	167		
29	November				39,646	168		
30	December				39,988	170		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$1,859	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					**$3,572**

		(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Reference	Tri- State CPI Factor	Inflation Factor	Expense In Year	Amount for Average	Total
1	4/1/2019 - 3/31/2020		-	1.22049	$32,500	$39,666	
2	4/1/2020 - 3/31/2021		0.00696	1.22049	$118,822	$145,021	
3	4/1/2021 - 3/31/2022		0.05645	1.21206	$56,495	$68,475	
4	4/1/2022 - 3/31/2023		0.07555	1.14730	$17,144	$19,670	
5	4/1/2023 - 3/31/2024		0.03888	1.06670	$67,284	$71,772	
6	2024		0.01671	1.02679			
7	2025		0.00991	1.00991			
8							
9	Average Storm Restoration Expense at 2025 cost levels	AVERAGE L1 to L5					$68,921
10							
11	FPFTY Budget						$54,708
12							
13	**Pro Forma Adjustment for Storm Expense Normalization**	L9 - L11					**$14,213**

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		(1)	(2)
Line No.	Description	Reference	Total
1	Final Tax Accounting Repair Credit (TARC) - Electric		
2	Residential		(36)
3	Small C&I		(14)
4	Large C&I		(9)
5	Street Lighting		(3)
6	Sub-total TARC Credit	SUM L2 to L5	($62)
7	Final Federal Tax Adjustment Credit (FTAC) - Electric		
8	Residential		($37)
9	Small C&I		(1)
10	Street Lighting		(0)
11	Large C&I & Railroads		15
12	Sub-total FTAC Credit	SUM L8 to L11	($23)
13	Total TARC and FTAC Credit	L6 + L12	($86)
14	Amortization Years		2
15	Pro Forma Adjustment Amount	L13 / L14	($43)
16			
17	EV Incentive Rebates		$1,000

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			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description		Transmission Percentage / Reference	Total Electric	Transmission Elimination	Distribution	Pro Forma Adjustments	Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense		17.825%	$6,924	($1,234)	$5,690		$5,690
2	Use Tax Accrued		17.825%	2,443	(435)	2,007		2,007
3	Real Estate Tax Accrued		17.825%	5,988	(1,067)	4,920		4,920
4	Miscellaneous TOTI		12.373%					
5	Payroll Tax Accrued		12.373%	14,402	(1,782)	12,620	431	13,051
6		Sub-total TOTI - Other	SUM L1 to L5	$29,756	($4,519)	$25,237	$431	$25,668
7								
8	Gross Receipt Tax			$172,280		$172,280	($5,615)	$166,664
9								
10	**Total**		L6 + L8	**$202,036**	**($4,519)**	**$197,517**	**($5,184)**	**$192,333**

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		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Total Payroll Charged to Expense		$167,922
2	Payroll Tax Expense		$12,620
3	Payroll Tax Expense - Percent	L2 / L1	7.52%
4	Pro Forma Increase in S&W		$5,736
5	**Payroll Tax Pro Forma**	L3 * L4	**$431**

		(1)	(2)
Line No.	Description	Reference	Total
1	**GROSS RECEIPTS TAX PRO FORMA AT PRESENT RATE**		
2			
3	Residential		$1,616,574
4	Residential Heating		358,919
5	Small C&I		417,041
6	Large C&I		237,936
7	Railroads & Railways		7,059
8	Street Lighting & Highway		22,848
9	Interdepartmental Sales - Electric		
10	Transmission		199,791
11	Sub-total	SUM L3 to L10	$2,860,167
12			
13	Forfeited Discounts - Electric		$12,224
14	Uncollectible Accounts		(47,572)
15	COVID-19 Related Incremental Bad Debt Expense		
16	Sub-total	SUM L13 to L15	($35,348)
17			
18	Total FPFTY at Present Rates	L11 + L16	$2,824,819
19			
20	Gross Receipts Tax Rate		5.90%
21			
22	Pro Forma Gross Receipts Expense at Present Rates	L18 * L20	$166,664
23			
24	FPFTY Budget		$172,280
25			
26	**Net Adjustment**	L22 - L24	**($5,615)**

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Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	$2,703	$357	$2,346	$357	$3,060
2			PECO Elec 3650 PA LTIIP	4,037	440	3,597	440	4,478
3			PECO Elec 3660 PA LTIIP	4,615	723	3,892	723	5,338
4			PECO Elec 3670 PA LTIIP	6,084	764	5,320	764	6,847
5			PECO Elec 3705 SM UD RES PA	9,577		9,577		9,577
6			PECO Elec 3706 Non DOE Rcv PA	2,210		2,210		2,210
7			PECO Elec 3707 SM RES PA	5,764	96	5,668	96	5,861
8			PECO Elec 3708 SM SCI PA	832	3	829	3	835
9			PECO Elec 3709 SM LCI PA	1,207	20	1,187	20	1,227
10			PECO Elec Dist-ARC EXP PA	(21)		(21)		(21)
11			PECO Electric 3611 PA	1,963	143	1,820	143	2,106
12			PECO Electric 3612 PA	2,983	145	2,838	145	3,127
13			PECO Electric 3613 PA	198	0	198	0	199
14			PECO Electric 3620 PA	25,211	1,006	24,205	1,006	26,217
15			PECO Electric 3640 PA	29,752	1,970	27,782	1,970	31,722
16			PECO Electric 3650 PA	45,704	2,455	43,249	2,455	48,159
17			PECO Electric 3660 PA	11,794	939	10,855	939	12,733
18			PECO Electric 3670 PA	41,404	2,435	38,969	2,435	43,840
19			PECO Electric 3680 PA	20,873	1,090	19,783	1,090	21,963
20			PECO Electric 3691 PA	4,008	154	3,854	154	4,162
21			PECO Electric 3692 PA	5,101	63	5,038	63	5,164
22			PECO Electric 3701 PA	188	12	176	12	201
23			PECO Electric 3710 PA	4		4		4
24			PECO Electric 3730 PA	820	22	798	22	842
25			PECO Electric 3731 PA	74	0	73	0	74
26			PECO Electric 3732 PA	1,072	46	1,026	46	1,117
27			PECO Electric 3733 PA	34		34		34
28			Sub-total Electric - Distribution	$228,191	$12,884	$215,307	$12,884	$241,075
29			Sub-total Electric - Distribution	$228,191	$12,884	$215,307	$12,884	$241,075
30								
31		Common - General Plant	PECO Common 3901 PA	$4,228	$43	$4,185	$43	$4,272
32			PECO Common 3902 IL	16		16		16
33			PECO Common 3902 PA	4,714	352	4,361	352	5,066
34			PECO Common 3903 PA	116	10	106	10	125
35			PECO Common 3911 PA	13		13		13
36			PECO Common 3912 PA	2,326	28	2,299	28	2,354
37			PECO Common 3913 IL	1,480	197	1,283	197	1,677
38			PECO Common 3913 PA	12,199	1,831	10,368	1,831	14,031
39			PECO Common 3930 PA	99	1	99	1	100
40			PECO Common 3941 PA	0		0		0
41			PECO Common 3942 PA	66		66		66
42			PECO Common 3970 PA	7,006	169	6,837	169	7,175

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
43			PECO Common 3980 PA	84		84		84
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	12		12		12
45			PECO Elec 3919 SM Comp Equip IL	24		24		24
46			PECO Elec 3919 SM Comp Equip MD	8		8		8
47			PECO Elec 3919 SM Comp Equip NC	5		5		5
48			PECO Elec 3919 SM Comp Equip PA	7		7		7
49			PECO Elec 3949 SM Tools PA	6		6		6
50			PECO Elec 3979 SM Comm Equip PA	2,606	24	2,582	24	2,630
51			PECO Electric 3901 PA	805	5	799	5	810
52			PECO Electric 3902 PA	402	3	399	3	406
53			PECO Electric 3903 PA	8		8		8
54			PECO Electric 3911 PA	0		0		0
55			PECO Electric 3912 PA	71	2	69	2	74
56			PECO Electric 3913 PA	5,468	141	5,327	141	5,609
57			PECO Electric 3930 PA	4		4		4
58			PECO Electric 3940 PA	3,891	147	3,744	147	4,038
59			PECO Electric 3951 PA	11		11		11
60			PECO Electric 3952 PA	0		0		0
61			PECO Electric 3970 PA	8,136	195	7,941	195	8,332
62			PECO Electric 3980 PA	84	6	78	6	90
63			Sub-total Electric - General Plant	$53,897	$3,156	$50,742	$3,156	$57,053
64			Sub-total Electric - General Plant	$53,897	$3,156	$50,742	$3,156	$57,053
65								
66		Electric - Transmission	PECO Electric 3521 PA	$398	$0	$398	$0	$398
67			PECO Electric 3522 MD	1		1		1
68			PECO Electric 3522 NJ	0		0		0
69			PECO Electric 3522 PA	1,719	33	1,686	33	1,753
70			PECO Electric 3523 NJ	0		0		0
71			PECO Electric 3523 PA	49		49		49
72			PECO Electric 3530 NJ	65		65		65
73			PECO Electric 3530 PA	19,515	279	19,236	279	19,795
74			PECO Electric 3540 DE	91		91		91
75			PECO Electric 3540 MD	52		52		52
76			PECO Electric 3540 NJ	216		216		216
77			PECO Electric 3540 PA	3,149	9	3,140	9	3,159
78			PECO Electric 3550 PA	596	20	577	20	616
79			PECO Electric 3560 DE	5		5		5
80			PECO Electric 3560 MD	12		12		12
81			PECO Electric 3560 NJ	154	4	150	4	157
82			PECO Electric 3560 PA	5,668	225	5,443	225	5,892
83			PECO Electric 3570 PA	1,157	77	1,079	77	1,234
84			PECO Electric 3580 PA	2,454	65	2,388	65	2,519

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
85			PECO Electric 3590 NJ	4		4		4
86			PECO Electric 3590 PA	28	1	28	1	29
87			Sub-total Electric - Transmission	$35,333	$713	$34,620	$713	$36,047
88								
89			Sub-total 403.0 Depreciation Expense	$317,421	$16,753	$300,668	$16,753	$334,175
90			Sub-total Electric - Transmission	$35,333	$713	$34,620	$713	$36,047
91								
92	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	$12,690	$36	$12,653	$36	$12,726
93			PECO - BIDA - Smart Energy Services	55	1	54	1	55
94			PECO - Distribution - ADMS	4,138	23	4,115	23	4,160
95			PECO - Distribution - IT	2,001	612	1,389	612	2,613
96			PECO - Transmission - IT	619	70	549	70	688
97			PECO Com 3030-Apollo SW	967		967		967
98			PECO Com 3030-BIDA Customer Project	130		130		130
99			PECO Com 3030-BIDA-AMI Ph2 SW	2,139		2,139		2,139
100			PECO Com 3030-CIS Transformation SW	120		120		120
101			PECO Com 3030-Cloud Serv 3 yr	6,069	169	5,901	169	6,238
102			PECO Com 3030-Cloud Serv 5 yr	2,585		2,585		2,585
103			PECO Com 3030-Common MDM SW	228		228		228
104			PECO Com 3030-EU Digital Program We	1,987		1,987		1,987
105			PECO Com 3030-EU oneMDS SW	5,269		5,269		5,269
106			PECO Com 3030-IT Cust Mobile App SW	111		111		111
107			PECO Com 3030-IVR System PA	159		159		159
109			PECO Com 3030-Misc 5 yr FR PA	9,884	2,098	7,787	2,098	11,982
110			PECO Com 3030-Misc 5 yr PA	60		60		60
111			PECO Com 3030-Mobile Dispatch Mappi	5,842		5,842		5,842
112			PECO Com 3030-OBIEE Migration SW	275		275		275
113			PECO Com 3030-PECO RNI Upgrade SW	(0)		(0)		(0)
114			PECO Elec 303 SM AMOS PA	111		111		111
115			PECO Elec 303-BIDA Grid T&D Domain	1,797		1,797		1,797
116			PECO Elec 303-CFP - Outage SW D	566		566		566
117			PECO Elec 303-EMS Implementation Pr	3,182		3,182		3,182
118			PECO Elec 303-EU Custom Analytics S	158		158		158
119			PECO Elec 303-EU Load Forecast SW	723		723		723
120			PECO Elec 303-EU Ratings DB SW D	12		12		12
121			PECO Elec 303-EU Ratings DB SW T	155		155		155
122			PECO Elec 303-EU TOA Implementation	395		395		395
123			PECO Elec 303-PECO RNI Upgrade SW D	591		591		591
124			PECO Elec 303-SES IV D SW	2,364		2,364		2,364
125			PECO Elec 3030-Cloud Serv 3 yr	32		32		32
126			PECO Elec 3030-Cloud Serv 5 yr	626		626		626
127			PECO Electric 303 Misc 5 FR PA	4,382		4,382		4,382

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
128			Sub-total Electric - Intangible Plant	$70,420	$3,007	$67,413	$3,007	$73,428
129								
130			Sub-total 404.0 Amort. of Limited-Term Electric Plant	$70,420	$3,007	$67,413	$3,007	$73,428
131								
132			**Total**	$387,842	$19,761	$368,081	$19,761	$407,603
133			Sub-total Electric - Intangible Plant	$70,420	$3,007	$67,413	$3,007	$73,428
134								
135			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.	$70,420	$3,007	$67,413	$3,007	$73,428

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$2,703	$357	$2,346	$357	$3,060
2			PECO Elec 3650 PA LTIIP	1.0000	4,037	440	3,597	440	4,478
3			PECO Elec 3660 PA LTIIP	1.0000	4,615	723	3,892	723	5,338
4			PECO Elec 3670 PA LTIIP	1.0000	6,084	764	5,320	764	6,847
5			PECO Elec 3705 SM UD RES PA	1.0000	9,577		9,577		9,577
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	2,210		2,210		2,210
7			PECO Elec 3707 SM RES PA	1.0000	5,764	96	5,668	96	5,861
8			PECO Elec 3708 SM SCI PA	1.0000	832	3	829	3	835
9			PECO Elec 3709 SM LCI PA	1.0000	1,207	20	1,187	20	1,227
10			PECO Elec Dist-ARC EXP PA	1.0000	(21)		(21)		(21)
11			PECO Electric 3611 PA	1.0000	1,963	143	1,820	143	2,106
12			PECO Electric 3612 PA	1.0000	2,983	145	2,838	145	3,127
13			PECO Electric 3613 PA	1.0000	198	0	198	0	199
14			PECO Electric 3620 PA	1.0000	25,211	1,006	24,205	1,006	26,217
15			PECO Electric 3640 PA	1.0000	29,752	1,970	27,782	1,970	31,722
16			PECO Electric 3650 PA	1.0000	45,704	2,455	43,249	2,455	48,159
17			PECO Electric 3660 PA	1.0000	11,794	939	10,855	939	12,733
18			PECO Electric 3670 PA	1.0000	41,404	2,435	38,969	2,435	43,840
19			PECO Electric 3680 PA	1.0000	20,873	1,090	19,783	1,090	21,963
20			PECO Electric 3691 PA	1.0000	4,008	154	3,854	154	4,162
21			PECO Electric 3692 PA	1.0000	5,101	63	5,038	63	5,164
22			PECO Electric 3701 PA	1.0000	188	12	176	12	201
23			PECO Electric 3710 PA	1.0000	4		4		4
24			PECO Electric 3730 PA	1.0000	820	22	798	22	842
25			PECO Electric 3731 PA	1.0000	74	0	73	0	74
26			PECO Electric 3732 PA	1.0000	1,072	46	1,026	46	1,117
27			PECO Electric 3733 PA	1.0000	34		34		34
28			Sub-total Electric - Distribution		$228,191	$12,884	$215,307	$12,884	$241,075
29			Sub-total Electric - Distribution		$228,191	$12,884	$215,307	$12,884	$241,075
30									
31		Common - General Plant	PECO Common 3901 PA	0.7693	$3,253	$33	$3,219	$33	$3,286
32			PECO Common 3902 IL	0.7693	12		12		12
33			PECO Common 3902 PA	0.7693	3,626	271	3,355	271	3,897
34			PECO Common 3903 PA	0.7693	89	7	81	7	96
35			PECO Common 3911 PA	0.7693	10		10		10
36			PECO Common 3912 PA	0.7693	1,790	21	1,768	21	1,811
37			PECO Common 3913 IL	0.7693	1,139	152	987	152	1,290
38			PECO Common 3913 PA	0.7693	9,385	1,409	7,976	1,409	10,794
39			PECO Common 3930 PA	0.7693	77	1	76	1	77
40			PECO Common 3941 PA	0.7693	0		0		0
41			PECO Common 3942 PA	0.7693	51		51		51
42			PECO Common 3970 PA	0.7693	5,390	130	5,260	130	5,520

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
43			PECO Common 3980 PA	0.7693	65		65		65
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	1.0000	12		12		12
45			PECO Elec 3919 SM Comp Equip IL	1.0000	24		24		24
46			PECO Elec 3919 SM Comp Equip MD	1.0000	8		8		8
47			PECO Elec 3919 SM Comp Equip NC	1.0000	5		5		5
48			PECO Elec 3919 SM Comp Equip PA	1.0000	7		7		7
49			PECO Elec 3949 SM Tools PA	1.0000	6		6		6
50			PECO Elec 3979 SM Comm Equip PA	1.0000	2,606	24	2,582	24	2,630
51			PECO Electric 3901 PA	1.0000	805	5	799	5	810
52			PECO Electric 3902 PA	1.0000	402	3	399	3	406
53			PECO Electric 3903 PA	1.0000	8		8		8
54			PECO Electric 3911 PA	1.0000	0		0		0
55			PECO Electric 3912 PA	1.0000	71	2	69	2	74
56			PECO Electric 3913 PA	1.0000	5,468	141	5,327	141	5,609
57			PECO Electric 3930 PA	1.0000	4		4		4
58			PECO Electric 3940 PA	1.0000	3,891	147	3,744	147	4,038
59			PECO Electric 3951 PA	1.0000	11		11		11
60			PECO Electric 3952 PA	1.0000	0		0		0
61			PECO Electric 3970 PA	1.0000	8,136	195	7,941	195	8,332
62			PECO Electric 3980 PA	1.0000	84	6	78	6	90
63			Sub-total Electric - General Plant		$46,434	$2,549	$43,886	$2,549	$48,983
64			Sub-total Electric - General Plant		$46,434	$2,549	$43,886	$2,549	$48,983
65									
66		Electric - Transmission	PECO Electric 3521 PA	1.0000	$398	$0	$398	$0	$398
67			PECO Electric 3522 MD	1.0000	1		1		1
68			PECO Electric 3522 NJ	1.0000	0		0		0
69			PECO Electric 3522 PA	1.0000	1,719	33	1,686	33	1,753
70			PECO Electric 3523 NJ	1.0000	0		0		0
71			PECO Electric 3523 PA	1.0000	49		49		49
72			PECO Electric 3530 NJ	1.0000	65		65		65
73			PECO Electric 3530 PA	1.0000	19,515	279	19,236	279	19,795
74			PECO Electric 3540 DE	1.0000	91		91		91
75			PECO Electric 3540 MD	1.0000	52		52		52
76			PECO Electric 3540 NJ	1.0000	216		216		216
77			PECO Electric 3540 PA	1.0000	3,149	9	3,140	9	3,159
78			PECO Electric 3550 PA	1.0000	596	20	577	20	616
79			PECO Electric 3560 DE	1.0000	5		5		5
80			PECO Electric 3560 MD	1.0000	12		12		12
81			PECO Electric 3560 NJ	1.0000	154	4	150	4	157
82			PECO Electric 3560 PA	1.0000	5,668	225	5,443	225	5,892
83			PECO Electric 3570 PA	1.0000	1,157	77	1,079	77	1,234
84			PECO Electric 3580 PA	1.0000	2,454	65	2,388	65	2,519

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
85			PECO Electric 3590 NJ	1.0000	4		4		4
86			PECO Electric 3590 PA	1.0000	28	1	28	1	29
87			Sub-total Electric - Transmission		$35,333	$713	$34,620	$713	$36,047
88									
89			Sub-total 403.0 Depreciation Expense		$309,959	$16,146	$293,813	$16,146	$326,105
90			Sub-total Electric - Transmission		$35,333	$713	$34,620	$713	$36,047
91									
92	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	0.7450	$9,454	$27	$9,427	$27	$9,481
93			PECO - BIDA - Smart Energy Services	1.0000	55	1	54	1	55
94			PECO - Distribution - ADMS	1.0000	4,138	23	4,115	23	4,160
95			PECO - Distribution - IT	1.0000	2,001	612	1,389	612	2,613
96			PECO - Transmission - IT	1.0000	619	70	549	70	688
97			PECO Com 3030-Apollo SW	0.7693	744		744		744
98			PECO Com 3030-BIDA Customer Project	0.7693	100		100		100
99			PECO Com 3030-BIDA-AMI Ph2 SW	0.7693	1,645		1,645		1,645
100			PECO Com 3030-CIS Transformation SW	0.7693	92		92		92
101			PECO Com 3030-Cloud Serv 3 yr	0.7693	4,669	130	4,539	130	4,799
102			PECO Com 3030-Cloud Serv 5 yr	0.7693	1,989		1,989		1,989
103			PECO Com 3030-Common MDM SW	0.7693	176		176		176
104			PECO Com 3030-EU Digital Program We	0.7693	1,529		1,529		1,529
105			PECO Com 3030-EU oneMDS SW	0.7693	4,053		4,053		4,053
106			PECO Com 3030-IT Cust Mobile App SW	0.7693	85		85		85
107			PECO Com 3030-IVR System PA	0.7693	122		122		122
109			PECO Com 3030-Misc 5 yr FR PA	0.7693	7,604	1,614	5,990	1,614	9,218
110			PECO Com 3030-Misc 5 yr PA	0.7693	46		46		46
111			PECO Com 3030-Mobile Dispatch Mappi	0.7693	4,494		4,494		4,494
112			PECO Com 3030-OBIEE Migration SW	0.7693	212		212		212
113			PECO Com 3030-PECO RNI Upgrade SW	0.7693	(0)		(0)		(0)
114			PECO Elec 303 SM AMOS PA	1.0000	111		111		111
115			PECO Elec 303-BIDA Grid T&D Domain	1.0000	1,797		1,797		1,797
116			PECO Elec 303-CFP - Outage SW D	1.0000	566		566		566
117			PECO Elec 303-EMS Implementation Pr	1.0000	3,182		3,182		3,182
118			PECO Elec 303-EU Custom Analytics S	1.0000	158		158		158
119			PECO Elec 303-EU Load Forecast SW	1.0000	723		723		723
120			PECO Elec 303-EU Ratings DB SW D	1.0000	12		12		12
121			PECO Elec 303-EU Ratings DB SW T	1.0000	155		155		155
122			PECO Elec 303-EU TOA Implementation	1.0000	395		395		395
123			PECO Elec 303-PECO RNI Upgrade SW D	1.0000	591		591		591
124			PECO Elec 303-SES IV D SW	1.0000	2,364		2,364		2,364
125			PECO Elec 3030-Cloud Serv 3 yr	1.0000	32		32		32
126			PECO Elec 3030-Cloud Serv 5 yr	1.0000	626		626		626
127			PECO Electric 303 Misc 5 FR PA	1.0000	4,382		4,382		4,382

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
128			Sub-total Electric - Intangible Plant		$58,920	$2,475	$56,445	$2,475	$61,395
129									
130			Sub-total 404.0 Amort. of Limited-Term Electric Plant		$58,920	$2,475	$56,445	$2,475	$61,395
131									
132			**Total**		$368,879	$18,621	$350,257	$18,621	$387,500
133			Sub-total Electric - Intangible Plant		$58,920	$2,475	$56,445	$2,475	$61,395
134									
135			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.		$58,920	$2,475	$56,445	$2,475	$61,395

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$2,703	$357	$2,346	$357	$3,060
2			PECO Elec 3650 PA LTIIP	1.0000	$4,037	440	3,597	440	4,478
3			PECO Elec 3660 PA LTIIP	1.0000	$4,615	723	3,892	723	5,338
4			PECO Elec 3670 PA LTIIP	1.0000	$6,084	764	5,320	764	6,847
5			PECO Elec 3705 SM UD RES PA	1.0000	$9,577		9,577		9,577
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	$2,210		2,210		2,210
7			PECO Elec 3707 SM RES PA	1.0000	$5,764	96	5,668	96	5,861
8			PECO Elec 3708 SM SCI PA	1.0000	$832	3	829	3	835
9			PECO Elec 3709 SM LCI PA	1.0000	$1,207	20	1,187	20	1,227
10			PECO Elec Dist-ARC EXP PA						
11			PECO Electric 3611 PA	1.0000	$1,963	143	1,820	143	2,106
12			PECO Electric 3612 PA	1.0000	$2,983	145	2,838	145	3,127
13			PECO Electric 3613 PA	1.0000	$198	0	198	0	199
14			PECO Electric 3620 PA	1.0000	$25,211	1,006	24,205	1,006	26,217
15			PECO Electric 3640 PA	1.0000	$29,752	1,970	27,782	1,970	31,722
16			PECO Electric 3650 PA	1.0000	$45,704	2,455	43,249	2,455	48,159
17			PECO Electric 3660 PA	1.0000	$11,794	939	10,855	939	12,733
18			PECO Electric 3670 PA	1.0000	$41,404	2,435	38,969	2,435	43,840
19			PECO Electric 3680 PA	1.0000	$20,873	1,090	19,783	1,090	21,963
20			PECO Electric 3691 PA	1.0000	$4,008	154	3,854	154	4,162
21			PECO Electric 3692 PA	1.0000	$5,101	63	5,038	63	5,164
22			PECO Electric 3701 PA	1.0000	$188	12	176	12	201
23			PECO Electric 3710 PA	1.0000	$4		4		4
24			PECO Electric 3730 PA	1.0000	$820	22	798	22	842
25			PECO Electric 3731 PA	1.0000	$74	0	73	0	74
26			PECO Electric 3732 PA	1.0000	$1,072	46	1,026	46	1,117
27			PECO Electric 3733 PA	1.0000	$34		34		34
28			Sub-total Electric - Distribution		$228,212	$12,884	$215,328	$12,884	$241,096
29			Sub-total Electric - Distribution		$228,212	$12,884	$215,328	$12,884	$241,096
30									
31		Common - General Plant	PECO Common 3901 PA	0.8763	$2,850	$29	$2,821	$29	$2,879
32			PECO Common 3902 IL	0.8763	11		11		11
33			PECO Common 3902 PA	0.8763	3,177	238	2,940	238	3,415
34			PECO Common 3903 PA	0.8763	78	7	71	7	84
35			PECO Common 3911 PA	0.8763	8		8		8
36			PECO Common 3912 PA	0.8763	1,568	19	1,549	19	1,587
37			PECO Common 3913 IL	0.8763	998	133	865	133	1,131
38			PECO Common 3913 PA	0.8763	8,224	1,234	6,989	1,234	9,458
39			PECO Common 3930 PA	0.8763	67	0	67	0	68
40			PECO Common 3941 PA	0.8763	0		0		0
41			PECO Common 3942 PA	0.8763	45		45		45
42			PECO Common 3970 PA	0.8763	4,723	114	4,609	114	4,837

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
43			PECO Common 3980 PA	0.8763	57		57		57
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	0.8763	11		11		11
45			PECO Elec 3919 SM Comp Equip IL	0.8763	21		21		21
46			PECO Elec 3919 SM Comp Equip MD	0.8763	7		7		7
47			PECO Elec 3919 SM Comp Equip NC	0.8763	4		4		4
48			PECO Elec 3919 SM Comp Equip PA	0.8763	7		7		7
49			PECO Elec 3949 SM Tools PA	0.8763	6		6		6
50			PECO Elec 3979 SM Comm Equip PA	0.8763	2,283	21	2,263	21	2,304
51			PECO Electric 3901 PA	0.8763	705	5	700	5	710
52			PECO Electric 3902 PA	0.8763	353	3	349	3	356
53			PECO Electric 3903 PA	0.8763	7		7		7
54			PECO Electric 3911 PA	0.8763	0		0		0
55			PECO Electric 3912 PA	0.8763	63	2	60	2	65
56			PECO Electric 3913 PA	0.8763	4,791	123	4,668	123	4,915
57			PECO Electric 3930 PA	0.8763	3		3		3
58			PECO Electric 3940 PA	0.8763	3,410	129	3,281	129	3,538
59			PECO Electric 3951 PA	0.8763	10		10		10
60			PECO Electric 3952 PA	0.8763	0		0		0
61			PECO Electric 3970 PA	0.8763	7,129	171	6,958	171	7,301
62			PECO Electric 3980 PA	0.8763	74	5	68	5	79
63			Sub-total Electric - General Plant		$40,689	$2,233	$38,456	$2,233	$42,922
64			Sub-total Electric - General Plant		$40,689	$2,233	$38,456	$2,233	$42,922
65									
66		Electric - Transmission	PECO Electric 3521 PA						
67			PECO Electric 3522 MD						
68			PECO Electric 3522 NJ						
69			PECO Electric 3522 PA						
70			PECO Electric 3523 NJ						
71			PECO Electric 3523 PA						
72			PECO Electric 3530 NJ						
73			PECO Electric 3530 PA						
74			PECO Electric 3540 DE						
75			PECO Electric 3540 MD						
76			PECO Electric 3540 NJ						
77			PECO Electric 3540 PA						
78			PECO Electric 3550 PA						
79			PECO Electric 3560 DE						
80			PECO Electric 3560 MD						
81			PECO Electric 3560 NJ						
82			PECO Electric 3560 PA						
83			PECO Electric 3570 PA						
84			PECO Electric 3580 PA						

				(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Account	Plant Account	Depreciation Category	Functional Allocation Factor	Depr on Existing Assets + Adds (Function)	Depr on Adds (Function)	Depr on Existing Assets (Function)	Annualize Current Yr Depr (Function)	Pro Forma Test Yr Depr (Function)
85			PECO Electric 3590 NJ						
86			PECO Electric 3590 PA						
87			Sub-total Electric - Transmission						
88									
89			Sub-total 403.0 Depreciation Expense		$268,901	$15,117	$253,783	$15,117	$284,018
90			Sub-total Electric - Transmission						
91									
92	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	1.0000	$9,454	$27	$9,427	$27	$9,481
93			PECO - BIDA - Smart Energy Services	1.0000	55	1	54	1	55
94			PECO - Distribution - ADMS	0.8763	3,626	20	3,606	20	3,646
95			PECO - Distribution - IT	0.8763	1,753	536	1,217	536	2,289
96			PECO - Transmission - IT	0.8763	542	61	481	61	603
97			PECO Com 3030-Apollo SW	0.8763	652		652		652
98			PECO Com 3030-BIDA Customer Project	0.8763	88		88		88
99			PECO Com 3030-BIDA-AMI Ph2 SW	0.8763	1,442		1,442		1,442
100			PECO Com 3030-CIS Transformation SW	0.8763	81		81		81
101			PECO Com 3030-Cloud Serv 3 yr	0.8763	4,092	114	3,978	114	4,205
102			PECO Com 3030-Cloud Serv 5 yr	0.8763	1,743		1,743		1,743
103			PECO Com 3030-Common MDM SW	0.8763	154		154		154
104			PECO Com 3030-EU Digital Program We	0.8763	1,340		1,340		1,340
105			PECO Com 3030-EU oneMDS SW	0.8763	3,552		3,552		3,552
106			PECO Com 3030-IT Cust Mobile App SW	0.8763	75		75		75
107			PECO Com 3030-IVR System PA	0.8763	107		107		107
109			PECO Com 3030-Misc 5 yr FR PA	0.8763	6,663	1,414	5,249	1,414	8,077
110			PECO Com 3030-Misc 5 yr PA	0.8763	40		40		40
111			PECO Com 3030-Mobile Dispatch Mappi	0.8763	3,938		3,938		3,938
112			PECO Com 3030-OBIEE Migration SW	0.8763	186		186		186
113			PECO Com 3030-PECO RNI Upgrade SW	0.8763	(0)		(0)		(0)
114			PECO Elec 303 SM AMOS PA	1.0000	111		111		111
115			PECO Elec 303-BIDA Grid T&D Domain	0.8763	1,574		1,574		1,574
116			PECO Elec 303-CFP - Outage SW D	1.0000	566		566		566
117			PECO Elec 303-EMS Implementation Pr						
118			PECO Elec 303-EU Custom Analytics S	1.0000	158		158		158
119			PECO Elec 303-EU Load Forecast SW	1.0000	723		723		723
120			PECO Elec 303-EU Ratings DB SW D	1.0000	12		12		12
121			PECO Elec 303-EU Ratings DB SW T						
122			PECO Elec 303-EU TOA Implementation						
123			PECO Elec 303-PECO RNI Upgrade SW D	1.0000	591		591		591
124			PECO Elec 303-SES IV D SW	1.0000	2,364		2,364		2,364
125			PECO Elec 3030-Cloud Serv 3 yr	0.8763	28		28		28
126			PECO Elec 3030-Cloud Serv 5 yr	0.8763	549		549		549
127			PECO Electric 303 Misc 5 FR PA	0.8763	3,839		3,839		3,839

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
128			Sub-total Electric - Intangible Plant		$50,096	$2,172	$47,924	$2,172	$52,269
129									
130			Sub-total 404.0 Amort. of Limited-Term Electric Plant		$50,096	$2,172	$47,924	$2,172	$52,269
131									
132			**Total**		$318,997	$17,290	$301,707	$17,290	$336,287
133			Sub-total Electric - Intangible Plant		$50,096	$2,172	$47,924	$2,172	$52,269
134									
135			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.		$50,096	$2,172	$47,924	$2,172	$52,269

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Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$2,908,189	$465,038	$3,373,227
2	Operating Expenses		2,533,736	32,966	2,566,702
3	OIBIT	L1 - L2	$374,453	$432,072	$806,525
4					
5	Rate Base		$8,855,637		$8,855,637
6	Weighted Cost of Debt		2.130%		2.130%
7	Synchronized Interest Expense	L5 * L6	$188,625		$188,625
8	Base Taxable Income	L3 - L7	$185,828	$432,072	$617,900
9					
10	State Accelerated Tax Depreciation		$367,105		$367,105
11	Pro Forma Book Depreciation		336,287		336,287
12	State Tax Depreciation (Over) Under Book	L11 - L10	($30,819)		($30,819)
13	Regulatory Asset Programs M-1, Pension and Post Retirement & Other		(24,323)		(24,323)
14	Other Property Basis Adjustments (CIAC/ICM)		(58,325)		(58,325)
15	Removal Costs/Software		(7,598)		(7,598)
16	AFUDC Equity		(26,536)		(26,536)
17	Permanent Adjustments		4,315		4,315
18	Repair Deduction		(210,100)		(210,100)
19					
20	State Taxable Income	L8 + SUM (L12 to L18)	($167,557)	$432,072	$264,515
21					
22	State Income Tax Rate		7.99%	7.99%	7.99%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L22 * L20)	$13,388	($34,523)	($21,135)
24	Net Operating Loss Utilization %		40.00%	40.00%	40.00%
25	Net Operating Loss Utilization	- L24 * L23	(5,355)	13,809	8,454
26	State Income Tax Benefit / (Expense)	L23 + L25	$8,033	($20,714)	($12,681)
27					
28	Federal Accelerated Tax Depreciation		$357,203		$357,203
29	Pro Forma Book Depreciation		336,287		336,287
30	Federal Tax Deducts (Over) Under Book	L29 - L28	($20,916)		($20,916)
31	Regulatory Asset Programs M-1		(24,323)		(24,323)
32	Other Property Basis Adjustments (CIAC/ICM)		(58,325)		(58,325)
33	Removal Costs/Software		(7,598)		(7,598)
34	AFUDC Equity		(26,536)		(26,536)
35	Permanent Adjustments		4,315		4,315
36	Repair Deduction		(210,100)		(210,100)
37	Federal NOL				
38	Federal Taxable Income	L8 + L26 + SUM (L30 to L37)	($149,622)	$411,358	$261,737
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	-	$31,421	($86,385)	($54,965)
42	Corporate Alternative Minimum Tax		($45,820)		($45,820)
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	($6,367)	($107,099)	($113,465)
44					

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Line No.	Description	Reference	Present Rates	Rate Increase	Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($23,082)	$2,900	(20,182)
47	Deferred Taxes on Timing Differences- State		(6,604)		(6,604)
48	Deferred Taxes on State NOL		5,355	(13,809)	(8,454)
49	Excess Deferred Amortization		6,987		6,987
50	Excess Deferred Amortization - State (Net of Federal)		232		232
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax Expense on Flow Through Adjustment		(4,194)		(4,194)
53	Corporate Alternative Minimum Tax		45,820		45,820
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	$24,515	($10,909)	$13,606
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	$18,148	($118,008)	($99,859)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		$15		$15
60					
61	Combined Income Tax Benefit / (Expense)	SUM L56 to L59	$18,163	($118,008)	($99,845)
62					
63	**Federal Income Tax Benefit / (Expense)**	L41 + L46 + L49 + L51 + L52 + L59	**$11,147**	**($83,485)**	**($72,338)**
64	**State Income Tax Benefit / (Expense)**	L26 + L47 + L48 + L50	**$7,016**	**($34,523)**	**($27,507)**
65	**Total Income Tax Benefit / (Expense)**	L63 + L64	**$18,163**	**($118,008)**	**($99,845)**

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Reference	2018	2019	2020	2021	2022	Average
1	PECO Consolidated Taxable Income		$149,524	$191,310	($22,448)	$33,306	$135,993	
2								
3								
4	Consolidated Income Companies Taxable Income		$1,005,422	$931,575	$937,098	$1,705,766	$816,851	
5								
6								
7	Taxable Income Percentage to PECO	L1 / L4	14.87%	20.54%		1.95%	16.65%	
8								
9								
10	Consolidated Companies Loss		$ (85,736)	$ (162,524)	$ (249,053)	$ (575,746)	$ (108,853)	
11								
12								
13	PECO Allocation of Loss	L7 * L10	$ (12,750)	$ (33,376)	$ -	$ (11,242)	$ (18,122)	
14								
15								
16	Electric Percentage		106.61%	125.46%	-88.07%	376.30%	158.98%	
17								
18								
19	Loss Allocable to Electric	L13 * L16	($13,593)	($41,874)		($42,303)	($28,809)	
20								
21								
22								
23	Average for 2018 to 2022	Average L19						(25,316)
24								
25								
26	Tax Rate							21.00%
27								
28	**Section 1301.1(b) Differential**	L23 * L26						**$ (5,316)**

		(1)	(2)
Line No.	Description	Reference	Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		12,224
4	Total Customer Revenue		2,949,296
5	Shopping Revenue		1,082,504
6	LPC REVENUE	L3 / (L4 + L5)	0.003032
7	GROSS RECEIPTS TAX		(0.059000)
8	UNCOLLECTIBLE EXPENSES	D-10	(0.009708)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.002397)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.931927
13			
14	STATE INCOME TAX RATE		7.990%
15			
16	STATE INCOME TAX FACTOR	-	(0.074461)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.857466
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	-	(0.180068)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.677398
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.476236
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	25.453%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		7.990%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.079900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.920100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.193221)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.726879
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.375745
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	27.312%

PECO Exhibit MJT-2:

Principal Accounting Exhibit – Future Test Year ending December 31, 2024

Line No.	Description	Reference	(1) Present Rates	(2) Revenue Increase	(3) Total
1	**MEASURE OF VALUE**				
□	Utility Plant	C-2	$10,240,148		$10,240,148
□	Accumulated Depreciation	C-3	2,161,844		2,161,844
□	Common Plant - Net of Accum Depr	C-8	554,582		554,582
□	Net Plant in service	L2 - L3 + L4	$8,632,886		$8,632,886
□					
□	Working Capital	C-1	$222,289		$222,289
□	Accum Deferred Income Taxes	C-1	(595,742)		(595,742)
□	Customer Deposits	C-1	(57,291)		(57,291)
10	Customer Advances for Construction	C-1	(2,889)		(2,889)
11	Materials and Supplies	C-1	30,350		30,350
1□	Accum Deferred Income Taxes - Reg Liability	C-1	(281,253)		(281,253)
1□					
1□	TOTAL RATE BASE	SUM L5 to L12	$7,948,351		$7,948,351
1□					
1□	**OPERATING REVENUES AND EXPENSES**				
1□	Base Customer Charges	D-5	$1,757,401	$356,463	$2,113,864
1□	Electric Cost Revenue	D-5	$1,128,674		1,128,674
1□	Other Operating Revenues	D-5	$46,402	995	47,398
□0	Total Revenues	SUM L17 to L19	$2,932,477	$357,459	$3,289,936
□1					
□□	Operating Expenses	D-1	$2,547,038	$25,346	$2,572,384
□□					
□□	OIBIT	L20 - L22	$385,439	$332,112	$717,551
□□					
□□	Income Taxes @ Eff Inc Tax Rate	D-18	$797		$797
□□	Income Taxes @ Statutory Rates	D-18		($92,019)	($92,019)
□□					
□□	NET OPERATING INCOME	SUM L24 to L27	$386,236	$240,094	$626,330
□0					
□1	RATE OF RETURN	L29 / L14	4.86%		7.88%
□□					
□□	**REVENUE INCREASE REQUIRED**				
□□	Rate of Return at Present Rates	L31	4.86%		
□□					
□□	Rate of Return Required	B-7	7.88%		
□□					
□□	Change in ROR	L36 - L34	3.02%		
□□					
□0	Change in Operating Income	L14 * L38	$240,094		
□1					
□□	Gross Revenue Conversion Factor	D-19	1.485		
□□					
□□	Change in Revenues	L40 * L42	$356,463		
□□					
□□	**RETURN ON COMMON EQUITY**				
□□	Common Equity Ratio	B-7	53.40%		
□□	Common Equity Rate Base	L14 * L47	$4,244,419		
□□	NET OPERATING INCOME	L29	$386,236		
□0	Synchronized Interest Expense	D-18	$161,352		
□1	NET OPERATING INCOME - COMMON EQUITY	L49 - L50	$224,885		
□□	RATE OF RETURN ON COMMON EQUITY	L51 / L48	5.30%		

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$18,248,650
3	Construction Work In Progress (107)		649,862
4	Total Utility Plant	L2 + L3	$18,898,512
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		4,525,430
6	Net Utility Plant	L4 - L5	$14,373,082
7			
8	**Other Property and Investments**		
9	Non-Utility Property (121)		$11,249
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,385
11	Invest in Assoc Company (123)		7,447
12	Other Investments (124-129, 175-176)		27,679
13	Total Other Property and Investments	SUM L9 to L12	$44,990
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments (131-136)		$25,000
17	Customer Accounts Receivable (142)		453,358
18	Other Accounts Receivable (143)		35,952
19	Accum. Prov. for Uncollectible (144)		(93,617)
20	Receivables from Assoc. Comp. (146)		
21	Fuel Stock (151)		36,209
22	Plant Materials & Supplies (154)		67,547
23	Prepayments (165)		20,246
24	Accrued Utility Revenues (173)		196,892
25	Miscellaneous Current & Accrued Assets (174)		90,803
26	Total Current and Accrued Assets	SUM L16 to L25	$832,391
27			
28	**Deferred Debits**		
29	Unamortized Debt Expense (181)		$46,779
30	Other Regualtory Assets (182.3)		957,139
31	Miscellaneous Deferred Debits (186)		740,509
32	Unamortized Loss on Reacquired Debt (189)		710
33	Accumulated Deferred Income Taxes (190)		(0)
34	Total Deferred Debits	SUM L29 to L33	$1,745,138
35			
36	**TOTAL ASSETS**	L6+L13+L26+L34	$16,995,600

		(1)	(2)
Line No.	Description	Reference	Total - PECO
37	**Proprietary Capital**		
38	Common Stock Issued (201)		$1,423,004
39	Preferred Stock Issued (204)		
40	Other Paid-In Capital (208-211)		3,215,779
41	Capital Stock Expense (214)		(87)
42	Retained Earnings (215, 215.2, 216)		2,190,561
43	Unappropriated Undistributed Subsidiary Earnings (216.1)		
44	Accum Other Comprehensive Income (219)		
45	Total Propriety Capital & Margins	SUM L38 to L44	$6,829,258
46			
47	**Long Term Debt**		
48	Bonds (221)		$5,775,000
49	Advances from Associated Companies (223)		184,419
50	Other Long-Term Debt (224)		
51	Unamortized Premium on LTD (225)		
52	Unamortized Discount on LTD (226)		(23,151)
53	Total Long-Term Debt	SUM L48 to L52	$5,936,267
54			
55	**Other Non-Current Liabilities**		
56	Obligations under Capital Leases (227)		
57	Accum. Prov for Injuries & Damages (228.2)		$35,157
58	Accum. Prov for Pensions & Benefits (228.3)		303,423
59	Accum. Miscellaneous Operating Prov (228.4)		18,397
60	Asset Retirement Obligation (230)		26,348
61	Total Other Non-Current Liabilities	SUM L56 to L60	$383,325
62			
63	**Current and Accrued Liabilities**		
64	Notes Payable (231)		$118,557
65	Accounts Payable (232)		615,561
66	Notes Payable to Assoc. Companies (233)		
67	Accounts Payable to Assoc. Companies (234)		36,168
68	Customer Deposits (235)		78,872
69	Taxes Accrued (236)		(3,728)
70	Interest Accrued (237)		59,215
71	Dividends Declared (238)		
72	Tax Collections Payable (241)		33
73	Misc Current & Accrued Liabilities (242)		181,042
74	Total Current & Accrued Liabilities	SUM L64 to L73	$1,085,720
75			
76	**Other Deferred Credits**		
77	Customer Advances for Construction (252)		$4,172
78	Other Deferred Credits (253)		5,796
79	Other Regulatory Liabilities (254)		318,330
80	Deferred Investment Tax Credit (255)		308
81	Unamortized Gain on Reacquired Debt (257)		
82	Accumulated Deferred Income Taxes (281-283)		2,432,423
83	Total Other Deferred Credits	SUM L77 to L82	$2,761,030
84			
85	**TOTAL LIABILITIES AND OTHER CREDITS**	L45+L53+L61+L74+L83	$16,995,600

			(1)	(2)	(3)
Line No.	Category	Description	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$1,653,580		$1,653,580
2		Electric Cost Revenue	1,128,674		1,128,674
3		Transmission - All Classes	202,352		202,352
4		Other Revenues	305,262	$258,860	46,402
5		Total Operating Revenues	$3,289,867	$258,860	$3,031,007
6					
7	**Total Operating Expenses**	Operation & Maintenance Expenses	$2,161,097	$85,791	$2,075,306
8		Depreciation & Amortization Expense	328,780	46,630	282,149
9		Amortization of Regulatory Expense	11,196		11,196
10		Taxes Other Than Income Taxes - Other	203,621	4,434	199,187
11		Total Operating Expenses	$2,704,694	$136,856	$2,567,838
12					
13	**Net Utility Operating Income Before Income Tax**		**$585,173**	**$122,004**	**$463,169**

Line No.	Category	Description	Description	Account	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	440.0	$930,799		$930,799
2			Residential - House Heating	440.1	177,985		177,985
3			C & I Small	442.0	295,923		295,923
4			C & I Large	442.1	218,153		218,153
5			Street Lighting	444.0	8,345		8,345
6			Railroads & Railways	446.0	22,374		22,374
7			Intercompany	448.0			
8			Transmission - All Classes		202,352		202,352
9			Sub-total - Customer & Distribution Revenues		$1,855,931		$1,855,931
10							
11		Electric Cost Revenue	Residential	440.0	$726,764		$726,764
12			Residential - House Heating	440.1	188,794		188,794
13			C & I Small	442.0	160,260		160,260
14			C & I Large	442.1	52,012		52,012
15			Street Lighting	444.0	845		845
16			Intercompany	448.0			
17			Sub-total - Electric Cost Revenue		$1,128,674		$1,128,674
18							
19		Other Operating Revenues	Forfeited Discounts	450.0	$11,428		$11,428
20			Miscellaneous Service Revenues	451.0	3,684		3,684
21			Rent For Electric Property	454.0	32,595	$10,574	22,021
22			Other Electric Revenues	456.0	9,270		9,270
23			Transmission of Electricity for Others	456.1	248,286	248,286	
24			Sub-total - Other Operating Revenues		$305,262	$258,860	$46,402
25							
26			**TOTAL OPERATING REVENUES**		$3,289,867	$258,860	$3,031,007
27							

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FTY Amount	Non-Jurisdictional	Jurisdictional
28	**Operating Expenses**	Operation & Maintenance Expenses	Purchased Power	555.0	$1,057,282		$1,057,282
29			Operation & Supervision	560.0	8,620	$8,620	
30			Load Dispatching	561.0			
31			Scheduling, System Control & Dispatch	561.4	95,200		95,200
32			Transmission Service Studies	561.6			
33			Generation Service Studies	561.7			
34			Reliability, Planning & Standard Development	561.8	94,118		94,118
35			Station Expense	562.0	459	459	
36			Overhead Lines	563.0	577	577	
37			Underground Lines Expense	564.0			
38			Miscellaneous Expense	566.0	17,236	17,236	
39			Rents	567.0	15,794	15,794	
40			Maintenance of Structures	569.0	(35)	(35)	
41			Maintenance of Computer Hardware	569.1	102	102	
42			Maintenance of Computer Software	569.2	102	102	
43			Maintenance of Communication Equipment	569.3	145	145	
44			Maintenance of Station Equipment	570.0	13,529	13,529	
45			Maintenance of Overhead Lines	571.0	11,013	11,013	
46			Maintenance of Underground Lines	572.0	207	207	
47			Maintenance of Misc Transmission Plant	573.0	10,714	10,714	
48			Operation & Supervision	580.0	1,216		1,216
49			Load Dispatching	581.0			
50			Station Expenses	582.0	767		767
51			Overhead Lines Expenses	583.0	16,441		16,441
52			Underground Lines Expense	584.0	13,832		13,832
53			Meter Expenses	586.0	7,433		7,433
54			Customer Installations Expense	587.0	13,661		13,661
55			Miscellaneous Expense	588.0	85,996		85,996
56			Rents	589.0	3,438		3,438
57			Maintenance of Structures	591.0	6,274		6,274
58			Maintenance of Station Equipment	592.0	17,567		17,567
59			Maintenance of Overhead Lines	593.0	178,544		178,544
60			Maintenance of Underground Lines	594.0	36,485		36,485

				(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FTY Amount	Non-Jurisdictional	Jurisdictional
61			Maintenance of Line Transformers	595.0	2,266		2,266
62			Maintenance of Street Lighting & Signal Systems	596.0	1,858		1,858
63			Maintenance of Misc. Distribution	598.0	19,498		19,498
64			Supervision	901.0			
65			Meter Reading	902.0	916		916
66			Customer Records and Collection	903.0	101,136		101,136
67			Uncollectible Accounts	904.0	37,131		37,131
68			Miscellaneous Customer Accounts	905.0	3,458		3,458
69			Customer Assistance	908.0	108,961		108,961
70			Informational & Instructional	909.0	1,320		1,320
71			Miscellaneous Customer & Informational	910.0	937		937
72			Demonstrating & Selling	912.0	400		400
73			Miscellaneous Sales	916.0			
74			Administrative and General Salaries	920.0	21,527	(7,177)	28,705
75			Office Supplies and Expenses	921.0	5,932	1,608	4,324
76			Administrative Expenses Transferred-Credit	922.0			
77			Outside Service Employed	923.0	94,821	9,812	85,009
78			Property Insurance	924.0	807	90	717
79			Injuries & Damages	925.0	11,178	71	11,108
80			Employee Pensions and Benefits	926.0	22,928	1,697	21,231
81			Regulatory Commission Expenses	928.0	9,133	288	8,845
82			Duplicate Charges-Credit	929.0	(1,507)	(509)	(997)
83			Miscellaneous General Expenses	930.2	3,042	573	2,468
84			Maintenance of General Plant	935.0	8,641	877	7,763
85				Sub-total - O&M Expenses	$2,161,097	$85,791	$2,075,306
86							

Line No.	Category	Description	Description	Account	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
87		Depreciation & Amortization Expense	Depreciation & Amortization Expense	403.0	$272,353	$37,633	$234,720
88				404.0	56,427	8,998	47,429
89			Sub-total - Depreciation & Amortization Expense		$328,780	$46,630	$282,149
90							
91		Amortization of Regulatory Expense	Amortization of Regulatory Expense	407.3	$11,196		$11,196
92			Sub-total - Amortization of Regulatory Expense		$11,196		$11,196
93							
94		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	408.1	$203,621	$4,434	$199,187
95			Sub-total -Taxes Other Than Income Taxes - Other		$203,621	$4,434	$199,187
96							
97			**TOTAL OPERATING EXPENSES**		$2,704,694	$136,856	$2,567,838
98							
99			**NET UTILITY OPERATING INCOME BEFORE INCOME TAX**		**$585,173**	**$122,004**	**$463,169**
100							

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	440.0	$930,799		$930,799
2			Residential - House Heating	440.1	177,985		177,985
3			C & I Small	442.0	295,923		295,923
4			C & I Large	442.1	218,153		218,153
5			Railroads & Railways	446.0	8,345		8,345
6			Street Lighting	444.0	22,374		22,374
7			Intercompany	448.0			
8			Transmission - All Classes		202,352		202,352
9			Sub-total - Customer & Distribution Revenue		$1,855,931		$1,855,931
10							
11		**Electric Cost Revenue**	Residential	440.0	$726,764		$726,764
12			Residential - House Heating	440.1	188,794		188,794
13			C & I Small	442.0	160,260		160,260
14			C & I Large	442.1	52,012		52,012
15			Railroads & Railways	444.0			
16			Street Lighting	446.0	845		845
17			Intercompany	448.0			
18			Sub-total - Electric Cost Revenue		$1,128,674		$1,128,674
19							
20			**TOTAL OPERATING REVENUE**		$2,984,605		$2,984,605
21							
22	**OTHER REVENUE**	**Other Operating Revenue**	Forfeited Discounts	450.0	$11,428		$11,428
23			Miscellaneous Service Revenues	451.0	3,684		3,684
24			Sub-total - Other Operating Revenue		$15,111		$15,111
25							
26		**Other Electric Revenue**	Rent For Electric Property	454.0	$32,595	$10,574	$22,021
27			Other Electric Revenues	456.0	9,270		9,270
28			Transmission of Electricity for Others	456.1	248,286	248,286	
29			Sub-total - Other Electric Revenue		$290,151	$258,860	$31,291
30							
31			**TOTAL OTHER REVENUE**		$305,262	$258,860	$46,402
32							
33			**TOTAL REVENUE**		**$3,289,867**	**$258,860**	**$3,031,007**

Line No.	Category	Description	Account	Account	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**POWER SUPPLY EXPENSES**	Power Supply	Purchased Power	555.0	$1,057,282		$1,057,282
2			**TOTAL POWER SUPPLY EXPENSES**		$1,057,282		$1,057,282
3							
4	**TRANSMISSION EXPENSE**	Transmission Operations	Operation & Supervision	560.0	$8,620	$8,620	
5			Load Dispatching	561.0			
6			Scheduling, System Control & Dispatch	561.4	95,200		95,200
7			Transmission Service Studies	561.6			
8			Generation Service Studies	561.7			
9			Reliability, Planning & Standard Development	561.8	94,118		94,118
10			Station Expense	562.0	459	459	
11			Overhead Lines	563.0	577	577	
12			Underground Lines Expense	564.0			
13			Miscellaneous Expense	566.0	17,236	17,236	
14			Rents	567.0	15,794	15,794	
15			Sub-total Transmission Operations	SUM L4 to L14	$232,003	$42,686	$189,317
16							
17		Transmission Maintenance	Maintenance of Structures	569.0	($35)	($35)	
18			Maintenance of Computer Hardware	569.1	102	102	
19			Maintenance of Computer Software	569.2	102	102	
20			Maintenance of Communication Equipment	569.3	145	145	
21			Maintenance of Station Equipment	570.0	13,529	13,529	
22			Maintenance of Overhead Lines	571.0	11,013	11,013	
23			Maintenance of Underground Lines	572.0	207	207	
24			Maintenance of Misc Transmission Plant	573.0	10,714	10,714	
25			Sub-total Transmission Maintenance	SUM L17 to L24	$35,776	$35,776	
26							
27			**TOTAL TRANSMISSION EXPENSE**	L15 + L25	$267,779	$78,461	$189,317
28							
29	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation & Supervision	580.0	$1,216		$1,216
30			Load Dispatching	581.0			
31			Station Expenses	582.0	767		767
32			Overhead Lines Expenses	583.0	16,441		16,441
33			Underground Lines Expense	584.0	13,832		13,832
34			Meter Expenses	586.0	7,433		7,433
35			Customer Installations Expense	587.0	13,661		13,661
36			Miscellaneous Expense	588.0	85,996		85,996
37			Rents	589.0	3,438		3,438
38			Sub-total Distribution Operations	SUM L29 to L37	$142,784		$142,784
39							
40		Distribution Maintenance	Maintenance of Structures	591.0	6,274		6,274
41			Maintenance of Station Equipment	592.0	17,567		17,567
42			Maintenance of Overhead Lines	593.0	178,544		178,544
43			Maintenance of Underground Lines	594.0	36,485		36,485
44			Maintenance of Line Transformers	595.0	2,266		2,266
45			Maintenance of Street Lighting & Signal Systems	596.0	1,858		1,858
46			Maintenance of Misc. Distribution	598.0	19,498		19,498

Line No.	Category	Description	Account	Account	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
47			Sub-total Distribution Maintenance	SUM L40 to L46	$262,492		$262,492
48							
49			**TOTAL DISTRIBUTION EXPENSE**	L38 + L47	$405,275		$405,275
50							
51	**CUSTOMER ACCOUNTS**	Customer Accounts	Supervision	901.0			
52			Meter Reading	902.0	916		916
53			Customer Records and Collection	903.0	101,136		101,136
54			Uncollectible Accounts	904.0	37,131		37,131
55			Miscellaneous Customer Accounts	905.0	3,458		3,458
56			**TOTAL CUSTOMER ACCOUNTS**	SUM L51 to L55	$142,641		$142,641
57							
58	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$108,961		$108,961
59			Informational & Instructional	909.0	1,320		1,320
60			Miscellaneous Customer & Informational	910.0	937		937
61			**TOTAL CUSTOMER SERVICE & INFORMATION**	SUM L58 to L60	$111,218		$111,218
62							
63	**SALES**	Sales Expense	Demonstrating & Selling	912.0	$400		$400
64			Miscellaneous Sales	916.0			
65			**TOTAL SALES EXPENSE**	SUM L63 to L64	$400		$400
66							
67	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$21,527	($7,177)	$28,705
68			Office Supplies and Expenses	921.0	5,932	$1,608	4,324
69			Administrative Expenses Transferred-Credit	922.0			
70			Outside Service Employed	923.0	94,821	$9,812	85,009
71			Property Insurance	924.0	807	$90	717
72			Injuries & Damages	925.0	11,178	$71	11,108
73			Employee Pensions and Benefits	926.0	22,928	$1,697	21,231
74			Regulatory Commission Expenses	928.0	9,133	$288	8,845
75			Duplicate Charges-Credit	929.0	(1,507)	($509)	(997)
76			Miscellaneous General Expenses	930.2	3,042	$573	2,468
77			Sub-total A&G Operations	SUM L67 to L76	$167,861	$6,452	$161,408
78							
79		A&G Maintenance	Maintenance of General Plant	935.0	8,641	877	7,763
80							
81			TOTAL ADMINISTRATION & GENERAL	L77 + L79	$176,501	$7,330	$169,171
82							
83			**TOTAL O&M EXPENSE**	L2+L27+L49+L56+L61+L65+L81	$2,161,097	$85,791	$2,075,306
84							
85			TOTAL OPERATIONS EXPENSE		$1,862,830	$50,016	$1,812,814
86			TOTAL MAINTENANCE EXPENSE		298,267	35,776	262,492
87			**TOTAL O&M EXPENSE**	L85 + L86	**$2,161,097**	**$85,791**	**$2,075,306**
				ck	$914,498		$828,706

Line No.	Category	Description	Description	Account	(1) FTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
1	**Distribution**	**A&G Operations**	Administrative and General Salaries	920.0	$28,705	0.0000%		$28,705
2			Office Supplies and Expenses	921.0	4,303	0.0000%		4,303
3			Administrative Expenses Transferred-Credit	922.0		0.0000%		
4			Outside Service Employed	923.0	85,009	0.0000%		85,009
5			Property Insurance	924.0	717	0.0000%		717
6			Injuries and Damages	925.0	11,108	0.0000%		11,108
7			Employee Pensions and Benefits	926.0	21,231	0.0000%		21,231
8			Regulatory Commission Expenses	928.0	8,845	0.0000%		8,845
9			Duplicate Charges-Credit	929.0	(997)	0.0000%		(997)
10			Miscellaneous General Expenses	930.2	2,468	0.0000%		2,468
11			Sub-total A&G Operations - Distribution	SUM L1 to L10	$161,387			$161,387
12								
13		**A&G Maintenance**	Maintenance of General Plant	935.0	$7,763	0.0000%		$7,763
14			**ADMINISTRATION & GENERAL - DISTRIBUTION**	L11 + L13	$169,151			$169,151
15								
16	**Transmission**	**A&G Operations**	Administrative and General Salaries	920.0	($7,177)	100.0000%	($7,177)	
17			Office Supplies and Expenses	921.0	1,605	100.0000%	1,605	
18			Administrative Expenses Transferred-Credit	922.0		100.0000%		
19			Outside Service Employed	923.0	9,812	100.0000%	9,812	
20			Property Insurance	924.0	90	100.0000%	90	
21			Injuries and Damages	925.0	71	100.0000%	71	
22			Employee Pensions and Benefits	926.0	1,697	100.0000%	1,697	
23			Regulatory Commission Expenses	928.0	288	100.0000%	288	
24			Duplicate Charges-Credit	929.0	(509)	100.0000%	(509)	
25			Miscellaneous General Expenses	930.2	573	100.0000%	573	
26			Sub-total A&G Operations - Transmission	SUM L16 to L25	$6,449		$6,449	
27								
28		**A&G Maintenance**	Maintenance of General Plant	935.0	$877	100.0000%	$877	
29			**ADMINISTRATION & GENERAL - TRANSMISSION**	L26 + L28	$7,327		$7,327	
30								

Line No.	Category	Description	Description	Account	(1) FTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
31	**General**	**A&G Operations**	Administrative and General Salaries	920.0		12.3730%		
32			Office Supplies and Expenses	921.0	24	12.3730%	3	21
33			Administrative Expenses Transferred-Credit	922.0		12.3730%		
34			Outside Service Employed	923.0		12.3730%		
35			Property Insurance	924.0		12.3730%		
36			Injuries and Damages	925.0		12.3730%		
37			Employee Pensions and Benefits	926.0		12.3730%		
38			Regulatory Commission Expenses	928.0		12.3730%		
39			Duplicate Charges-Credit	929.0		12.3730%		
40			Miscellaneous General Expenses	930.2	0	12.3730%	0	0
41			Sub-total A&G Operations - General	SUM L31 to L40	$24		$3	$21
42								
43		**A&G Maintenance**	Maintenance of General Plant	935.0	$0	12.3730%	$0	$0
44			**ADMINISTRATION & GENERAL - GENERAL**	L41 + L43	$24		$3	$21
45								
46	**TOTAL**	**A&G Operations**	Administrative and General Salaries	920.0	$21,527		($7,177)	$28,705
47			Office Supplies and Expenses	921.0	5,932		1,608	4,324
48			Administrative Expenses Transferred-Credit	922.0				
49			Outside Service Employed	923.0	94,821		9,812	85,009
50			Property Insurance	924.0	807		90	717
51			Franchise Requirements	925.0	11,178		71	11,108
52			Employee Pensions and Benefits	926.0	22,928		1,697	21,231
53			Regulatory Commission Expenses	928.0	9,133		288	8,845
54			Duplicate Charges-Credit	929.0	(1,507)		(509)	(997)
55			Miscellaneous General Expenses	930.2	3,042		573	2,468
56			Sub-total A&G Operations - TOTAL	SUM L46 to L55	$167,861		$6,452	$161,408
57								
58		**A&G Maintenance**	Maintenance of General Plant	935.0	$8,641		$877	$7,763
59			**ADMINISTRATION & GENERAL - TOTAL**	L56 + L58	$176,501		$7,330	$169,171

		(1)	(2)	(3)	(4)
Line No.	Description	Percentage	Total	Transmission Elimination	Distribution
1	Public Utility Real Tax (PURTA) Total Expense	17.825%	$6,924	($1,234)	$5,690
2	Use Tax Accrued	17.825%	2,443	(435)	2,007
3	Real Estate Tax Accrued	17.825%	5,842	(1,041)	4,800
4	Miscellaneous TOTI	12.373%			
5	Payroll Tax Accrued	12.373%	13,927	(1,723)	12,204
6	Gross Receipt Tax		174,486		174,486
7	**Total**		**$203,621**	**($4,434)**	**$199,187**

Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effectivel nterest Rate	Average Weighted Cost Rate	Annualized Cost
				(1)	(2)	(3)	(4)	(5)	(6)
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $350 - 3.15% - Due 10-15-2025		$350,000		3.29%		
2					5.87%		0.19%	
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		75,000		6.00%		
4					1.26%		0.08%	
5		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
6					5.03%		0.30%	
7		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
8					2.94%		0.17%	
9		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
10					4.20%		0.21%	
11		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.21%		
12					5.03%		0.21%	
13		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
14					5.45%		0.21%	
15		PECO - FMB - $650 - 3.90% - Due 3-1-2048		650,000		4.08%		
16					10.91%		0.45%	
17		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
18					5.45%		0.17%	
19		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
20					5.87%		0.17%	
21		PECO - FMB - $375 - 3.05% - Due 3-15-2051		375,000		3.11%		
22					6.29%		0.20%	
23		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.90%		
24					6.29%		0.18%	
25		PECO - FMB - $350 - 4.60% - Due 5-15-2052		350,000		4.71%		
26					5.87%		0.28%	
27		PECO - FMB - $425 - 4.375% - Due 8-15-2052		425,000		4.46%		
28					7.13%		0.32%	
29		PECO - FMB - $575 - 4.90% - Due 6-15-2033		575,000		5.03%		
30					9.65%		0.49%	
31		PECO - FMB - $575 - 5.46% - Due 9-1-54		575,000		5.53%		
32					9.65%		0.53%	
33								
34		Sub-total Mortgage Bonds	SUM L1 to L32	$5,775,000	96.91%		4.16%	
35								
36	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.46%		
37					1.35%		0.10%	
38		PECO - TOPRS - $0.8 - Var (6.75%) - Due 4-6-2028		805		6.75%		
39					0.01%			
40		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
41					1.73%		0.10%	
42								
43		Sub-total Capital Securities	SUM L36 to L41	$184,419	3.09%		0.20%	
44								
45		Total Long-Term Debt	L34 + L43	$5,959,419	100.00%		4.36%	
46								
47		Adjustments for Tenders & Calls		(589)				
48								
49		Net Long-Term Debt	L45 + L47	$5,958,830				
50								
51		Annualized Cost		259,831				
52								
53		Adjustment for Tenders & Calls Reacquired		68				
54								
55		**Total**	L51 + L53	$259,899				4.36%

		(1)	(2)	(3)	(4)
Line No.	Description	Capitalization	Capitalization Ratio	Embedded Cost	Return %
1					
2	Long-Term Debt	$5,958,830	46.60%	4.36%	2.03%
3					
4	Common Equity	$6,829,258	53.40%	10.95%	5.85%
5					
6	Total	$12,788,087	100.00%		7.88%

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	FTY Amount	Non-Jurisdictional	Jurisdictional
1	Utility Plant	C-2	$12,423,195	$2,183,047	$10,240,148
2	Accumulated Depreciation	C-3	2,812,336	650,492	2,161,844
3	Common Plant	C-8	554,582		554,582
4	**Net Plant in Service**	L1 - L2 + L3	$10,165,441	$1,532,555	$8,632,886
5					
6	Working Capital	C-4	$222,289		$222,289
7	Accumulated Deferred Income Taxes	C-6	(595,742)		(595,742)
8	Customer Deposits	C-7	(57,291)		(57,291)
9	Customer Advances for Construction	C-9	(2,889)		(2,889)
10	Material & Supplies	C-11	30,350		30,350
11	ADIT - Reg Liability	C-12	(281,253)		(281,253)
12	**Total Measures of Value**	SUM L4 to L11	$9,480,905	$1,532,555	$7,948,351

Line No.	Category	Account	Reference	FTY Amount	Non-Jurisdictional	Jurisdictional
			(1)	(2)	(3)	(4)
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents		$163	$20	$143
3		E303 - Misc Intangible Plant		157,937	31,474	126,462
4		Sub-total Intangible Plant	SUM L1 to L3	$158,100	$31,495	$126,605
5						
6	**Transmission Plant**	E350 - Land and Land Rights		$75,731	$75,731	
7		E352 - Structures and Improvements		109,041	109,041	
8		E353 - Station Equipment		1,067,955	1,067,955	
9		E354 - Towers and Fixtures		293,214	293,214	
10		E355 - Poles and Fixtures		34,029	34,029	
11		E356 - Overhead Conductors, Devices		329,344	329,344	
12		E357 - Underground Conduit		59,161	59,161	
13		E358 - Undergrnd Conductors, Devices		140,124	140,124	
14		E359 - Roads and Trails		2,745	2,745	
15		E359.1 - ARO Costs Transmission Plt		503	503	
16		Sub-total Transmission Plant	SUM L6 to L15	$2,111,848	$2,111,848	
17						
18	**Distribution Plant**	E360 - Land and Land Rights		$54,159		$54,159
19		E361 - Structures and Improvements		232,091		232,091
20		E362 - Station Equipment		1,325,637		1,325,637
21		E364 - Poles, Towers and Fixtures		1,326,010		1,326,010
22		E365 - Overhead Conductors, Devices		2,164,605		2,164,605
23		E366 - Underground Conduit		904,829		904,829
24		E367 - Undergrnd Conductors, Devices		2,041,850		2,041,850
25		E368 - Line Transformers		852,034		852,034
26		E369 - Services		485,460		485,460
27		E370 - Meters		358,053		358,053
28		E371 - Installs on Customer Premiss		13,772		13,772
29		E373 - Street Lighting, Signal Systems		71,334		71,334
30		E374 - ARO Costs Distribution Plant		2,523		2,523
31		Sub-total Distribution Plant	SUM L18 to L30	$9,832,357		$9,832,357
32						
33	**General Plant**	E389 - Land and Land Rights		$1,063	$132	$932
34		E390 - Structures and Improvements		50,953	6,304	44,648
35		E391 - Office Furniture, Equipment		25,847	3,198	22,649
36		E392 - Transportation Equipment				
37		E393 - Stores Equipment		44	5	39
38		E394 - Tools, Shop, Garage Equipment		54,560	6,751	47,810
39		E395 - Laboratory Equipment		203	25	178
40		E396 - Power Operated Equipment				
41		E397 - Communication Equipment		185,578	22,962	162,616
42		E398 - Miscellaneous Equipment		703	87	616
43		E399 - Other Tangible Property				
44		E399.1 - ARO Costs General Plant		1,937	240	1,698
45		Sub-total General Plant	SUM L33 to L44	$320,889	$39,704	$281,185
46						
47		**Total**	L4+L16+L31+L45	**$12,423,195**	**$2,183,047**	**$10,240,148**

(1)

Line No.	Category	Account	Additions to Plant
1	**Intangible Plant**	E303 - Misc Intangible Plant	$51,220
2		Sub-total Intangible Plant	$51,220
3			
4	**Transmission Plant**	E350 - Land and Land Rights	($0)
5		E352 - Structures and Improvements	7,618
6		E353 - Station Equipment	61,811
7		E354 - Towers and Fixtures	2,002
8		E355 - Poles and Fixtures	4,433
9		E356 - Overhead Conductors, Devices	51,238
10		E357 - Underground Conduit	16,994
11		E358 - Undergrnd Conductors, Devics	13,943
12		E359 - Roads and Trails	124
13		Sub-total Transmission Plant	$158,162
14			
15	**Distribution Plant**	E361 - Structures and Improvements	$23,940
16		E362 - Station Equipment	81,716
17		E364 - Poles, Towers and Fixtures	185,693
18		E365 - Overhead Conductors, Devices	232,637
19		E366 - Underground Conduit	140,257
20		E367 - Undergrnd Conductors, Devics	257,973
21		E368 - Line Transformers	93,872
22		E369 - Services	18,140
23		E370 - Meters	11,232
24		E373 - Street Lighting,Signal Systm	5,777
25		Sub-total Distribution Plant	$1,051,237
26			
27	**General Plant**	E390 - Structures and Improvements	$63
28		E391 - Office Furniture, Equipment	2,467
29		E394 - Tools, Shop, Garage Equipmnt	2,577
30		E397 - Communication Equipment	4,606
31		E398 - Miscellaneous Equipment	16
32		Sub-total General Plant	$9,729
33			
34		**Total**	**$1,270,347**

(1)

Line No.	Category	Account	Plant Retirements
1	**Intangible Plant**	E303 - Misc Intangible Plant	($56,605)
2		Sub-total Intangible Plant	($56,605)
3			
4	**Transmission Plant**	E352 - Structures and Improvements	($73)
5		E353 - Station Equipment	(3,590)
6		E354 - Towers and Fixtures	(103)
7		E355 - Poles and Fixtures	(0)
8		E356 - Overhead Conductors, Devices	(72)
9		E357 - Underground Conduit	(7)
10		E358 - Undergrnd Conductors, Devics	(38)
11		E359.1 - ARO Costs Transmission Plt	(1)
12		Sub-total Transmission Plant	($3,884)
13			
14	**Distribution Plant**	E361 - Structures and Improvements	($669)
15		E362 - Station Equipment	(3,172)
16		E364 - Poles, Towers and Fixtures	(20,980)
17		E365 - Overhead Conductors, Devices	(16,652)
18		E366 - Underground Conduit	(835)
19		E367 - Undergrnd Conductors, Devics	(17,858)
20		E368 - Line Transformers	(16,468)
21		E369 - Services	(198)
22		E370 - Meters	(196)
23		E373 - Street Lighting,Signal Systm	(715)
24		E374 - ARO Costs Distribution Plt	(170)
25		Sub-total Distribution Plant	($77,913)
26			
27	**General Plant**	E390 - Structures and Improvements	($70)
28		E391 - Office Furniture, Equipment	(7,198)
29		E393 - Stores Equipment	(1)
30		E394 - Tools, Shop, Garage Equipmnt	(1,060)
31		E395 - Laboratory Equipment	(52)
32		E397 - Communication Equipment	(2,098)
33		E398 - Miscellaneous Equipment	(25)
34		E399.1 - ARO Costs General Plt	(21)
35		Sub-total General Plant	($10,525)
36			
37		**Total**	**($148,926)**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	E301 - Organization Costs						
2								
3		E302 - Franchises and Consents	$163	100.00%	$163	87.63%	$143	$20
4			$163		$163		$143	$20
5								
6		E303 - Misc Intangible Plant	$157,937	100.00%	$157,937	80.07%	$126,462	$31,474
7			$157,937		$157,937		$126,462	$31,474
8								
9		Sub-total Intangible Plant	$158,100		$158,100		$126,605	$31,495
10								
11	**Transmission Plant**	E350 - Land and Land Rights	$75,731	100.00%	$75,731			$75,731
12			$75,731		$75,731			$75,731
13								
14		E352 - Structures and Improvements	109,041	100.00%	109,041			109,041
15			109,041		109,041			109,041
16								
17		E353 - Station Equipment	1,067,955	100.00%	1,067,955			1,067,955
18			1,067,955		1,067,955			1,067,955
19								
20		E354 - Towers and Fixtures	293,214	100.00%	293,214			293,214
21			293,214		293,214			293,214
22								
23		E355 - Poles and Fixtures	34,029	100.00%	34,029			34,029
24			34,029		34,029			34,029
25								
26		E356 - Overhead Conductors, Devices	329,344	100.00%	329,344			329,344
27			329,344		329,344			329,344
28								
29		E357 - Underground Conduit	59,161	100.00%	59,161			59,161
30			59,161		59,161			59,161
31								
32		E358 - Undergrnd Conductors, Devices	140,124	100.00%	140,124			140,124
33			140,124		140,124			140,124
34								
35		E359 - Roads and Trails	2,745	100.00%	2,745			2,745
36			2,745		2,745			2,745
37								
38		E359.1 - ARO Costs Transmission Plt	503	100.00%	503			503
39			503		503			503
40								
41		Sub-total Transmission Plant	$2,111,848		$2,111,848			$2,111,848
42								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
43	**Distribution Plant**	E360 - Land and Land Rights	$54,159	100.00%	$54,159	100.00%	$54,159	
44			$54,159		$54,159		$54,159	
45								
46		E361 - Structures and Improvements	232,091	100.00%	232,091	100.00%	232,091	
47			232,091		232,091		232,091	
48								
49		E362 - Station Equipment	1,325,637	100.00%	1,325,637	100.00%	1,325,637	
50			1,325,637		1,325,637		1,325,637	
51								
52		E364 - Poles, Towers and Fixtures	1,326,010	100.00%	1,326,010	100.00%	1,326,010	
53			1,326,010		1,326,010		1,326,010	
54								
55		E365 - Overhead Conductors, Devices	2,164,605	100.00%	2,164,605	100.00%	2,164,605	
56			2,164,605		2,164,605		2,164,605	
57								
58		E366 - Underground Conduit	904,829	100.00%	904,829	100.00%	904,829	
59			904,829		904,829		904,829	
60								
61		E367 - Undergrnd Conductors, Devices	2,041,850	100.00%	2,041,850	100.00%	2,041,850	
62			2,041,850		2,041,850		2,041,850	
63								
64		E368 - Line Transformers	852,034	100.00%	852,034	100.00%	852,034	
65			852,034		852,034		852,034	
66								
67		E369 - Services	485,460	100.00%	485,460	100.00%	485,460	
68			485,460		485,460		485,460	
69								
70		E370 - Meters	358,053	100.00%	358,053	100.00%	358,053	
71			358,053		358,053		358,053	
72								
73		E371 - Installs on Customer Premiss	13,772	100.00%	13,772	100.00%	13,772	
74			13,772		13,772		13,772	
75								
76		E373 - Street Lighting, Signal Systems	71,334	100.00%	71,334	100.00%	71,334	
77			71,334		71,334		71,334	
78								
79		E374 - ARO Costs Distribution Plant	2,523	100.00%	2,523	100.00%	2,523	
80		Electric Nonrecoverable 100%						
81			2,523		2,523		2,523	
82								
83		Sub-total Distribution Plant	$9,832,357		$9,832,357		$9,832,357	
84								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
85	**General Plant**	E389 - Land and Land Rights	$1,063	100.00%	$1,063	87.63%	$932	$132
86			$1,063		$1,063		$932	$132
87								
88		E390 - Structures and Improvements	50,953	100.00%	50,953	87.63%	44,648	6,304
89			50,953		50,953		44,648	6,304
90								
91		E391 - Office Furniture, Equipment	25,847	100.00%	25,847	87.63%	22,649	3,198
92			25,847		25,847		22,649	3,198
93								
94		E393 - Stores Equipment	44	100.00%	44	87.63%	39	5
95			44		44		39	5
96								
97		E394 - Tools, Shop, Garage Equipment	54,560	100.00%	54,560	87.63%	47,810	6,751
98			54,560		54,560		47,810	6,751
99								
100		E395 - Laboratory Equipment	203	100.00%	203	87.63%	178	25
101			203		203		178	25
102								
103		E397 - Communication Equipment	185,578	100.00%	185,578	87.63%	162,616	22,962
104			185,578		185,578		162,616	22,962
105								
106		E398 - Miscellaneous Equipment	703	100.00%	703	87.63%	616	87
107			703		703		616	87
108								
109		E399.1 - ARO Costs General Plant	1,937	100.00%	1,937	87.63%	1,698	240
110			1,937		1,937		1,698	240
111								
112		Sub-total General Plant	$320,889		$320,889		$281,185	$39,704
113								
114								
115		**Total**	**$12,423,195**		**$12,423,195**		**$10,240,148**	**$2,183,047**

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents				
3		E303 - Misc Intangible Plant		$74,902	$20,034	$54,868
4		Sub-total Intangible Plant	SUM L1 to L3	$74,902	$20,034	$54,868
5						
6	**Transmission Plant**	E350 - Land and Land Rights		($0)	($0)	
7		E352 - Structures and Improvements		29,502	29,502	
8		E353 - Station Equipment		252,533	252,533	
9		E354 - Towers and Fixtures		176,479	176,479	
10		E355 - Poles and Fixtures		3,983	3,983	
11		E356 - Overhead Conductors, Devices		96,379	96,379	
12		E357 - Underground Conduit		2,942	2,942	
13		E358 - Undergrnd Conductors, Devices		49,370	49,370	
14		E359 - Roads and Trails		2,219	2,219	
15		E359.1 - ARO Costs Transmission Plt		93	93	
16		Sub-total Transmission Plant	SUM L6 to L15	$613,500	$613,500	
17						
18	**Distribution Plant**	E360 - Land and Land Rights		$310		310
19		E361 - Structures and Improvements		49,480		$49,480
20		E362 - Station Equipment		516,939		516,939
21		E364 - Poles, Towers and Fixtures		87,236		87,236
22		E365 - Overhead Conductors, Devices		299,650		299,650
23		E366 - Underground Conduit		187,827		187,827
24		E367 - Undergrnd Conductors, Devices		197,197		197,197
25		E368 - Line Transformers		178,996		178,996
26		E369 - Services		204,892		204,892
27		E370 - Meters		216,089		216,089
28		E371 - Installs on Customer Premises		11,229		11,229
29		E373 - Street Lighting, Signal Systems		34,982		34,982
30		E374 - ARO Costs Distribution Plant		2,046		2,046
31		Sub-total Distribution Plant	SUM L18 to L30	$1,986,873		$1,986,873
32						
33	**General Plant**	E389 - Land and Land Rights				
34		E390 - Structures and Improvements		$17,123	$2,119	$15,004
35		E391 - Office Furniture, Equipment		14,452	1,788	12,664
36		E392 - Transportation Equipment				
37		E393 - Stores Equipment		29	4	25
38		E394 - Tools, Shop, Garage Equipmnt		22,935	2,838	20,098
39		E395 - Laboratory Equipment		184	23	161
40		E396 - Power Operated Equipment				
41		E397 - Communication Equipment		80,740	9,990	70,750
42		E398 - Miscellaneous Equipment		(204)	(25)	(178)
43		E399 - Other Tangible Property				
44		E399.1 - ARO Costs General Plt		1,804	223	1,581
45		Sub-total General Plant	SUM L33 to L44	$137,062	$16,959	$120,103
46						
47		**Total**	L4+L16+L31+L45	**$2,812,336**	**$650,492**	**$2,161,844**

Line No.	Description	Account	(1) FTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
1	**Intangible Plant**	E302 - Franchises and Consents						
2								
3								
4		E303 - Misc Intangible Plant	$74,902	100.00%	$74,902	73.25%	$54,868	$20,034
5			$74,902	100.00%	$74,902	73.25%	$54,868	$20,034
6								
7		Sub-total Intangible Plant	$74,902		$74,902		$54,868	$20,034
8								
9	**Transmission Plant**	E350 - Land and Land Rights	($0)	100.00%	($0)			($0)
10			($0)		($0)			($0)
11								
12		E352 - Structures and Improvements	29,502	100.00%	29,502			29,502
13			29,502		29,502			29,502
14								
15		E353 - Station Equipment	252,533	100.00%	252,533			252,533
16			252,533		252,533			252,533
17								
18		E354 - Towers and Fixtures	176,479	100.00%	176,479			176,479
19			176,479		176,479			176,479
20								
21		E355 - Poles and Fixtures	3,983	100.00%	3,983			3,983
22			3,983		3,983			3,983
23								
24		E356 - Overhead Conductors, Devices	96,379	100.00%	96,379			96,379
25			96,379		96,379			96,379
26								
27		E357 - Underground Conduit	2,942	100.00%	2,942			2,942
28			2,942		2,942			2,942
29								
30		E358 - Undergrnd Conductors, Devices	49,370	100.00%	49,370			49,370
31			49,370		49,370			49,370
32								
33		E359 - Roads and Trails	2,219	100.00%	2,219			2,219
34			2,219		2,219			2,219
35								
36		E359.1 - ARO Costs Transmission Plt	93	100.00%	93			93
37			93		93			93
38								
39		Sub-total Transmission Plant	$613,500		$613,500			$613,500
40								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
41	**Distribution Plant**	E360 - Land and Land Rights	310	100.00%	310	100.00%	310	
42			310		310		310	
43								
44		E361 - Structures and Improvements	$49,480	100.00%	$49,480	100.00%	$49,480	
45			$49,480		$49,480		$49,480	
46								
47		E362 - Station Equipment	516,939	100.00%	516,939	100.00%	516,939	
48			516,939		516,939		516,939	
49								
50		E364 - Poles, Towers and Fixtures	87,236	100.00%	87,236	100.00%	87,236	
51			87,236		87,236		87,236	
52								
53		E365 - Overhead Conductors, Devices	299,650	100.00%	299,650	100.00%	299,650	
54			299,650		299,650		299,650	
55								
56		E366 - Underground Conduit	187,827	100.00%	187,827	100.00%	187,827	
57			187,827		187,827		187,827	
58								
59		E367 - Undergrnd Conductors, Devices	197,197	100.00%	197,197	100.00%	197,197	
60			197,197		197,197		197,197	
61								
62		E368 - Line Transformers	178,996	100.00%	178,996	100.00%	178,996	
63			178,996		178,996		178,996	
64								
65		E369 - Services	204,892	100.00%	204,892	100.00%	204,892	
66			204,892		204,892		204,892	
67								
68		E370 - Meters	216,089	100.00%	216,089	100.00%	216,089	
69			216,089		216,089		216,089	
70								
71		E371 - Installs on Customer Premises	11,229	100.00%	11,229	100.00%	11,229	
72			11,229		11,229		11,229	
73								
74		E373 - Street Lighting, Signal Systems	34,982	100.00%	34,982	100.00%	34,982	
75			34,982		34,982		34,982	
76								
77		E374 - ARO Costs Distribution Plant	2,046	100.00%	2,046	100.00%	2,046	
78								
79			2,046		2,046		2,046	
80								
81		Sub-total Distribution Plant	$1,986,873		$1,986,873		$1,986,873	
82								

Line No.	Description	Account	(1) FTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
83	**General Plant**	E389 - Land and Land Rights						
84								
85								
86		E390 - Structures and Improvements	$17,123	100.00%	$17,123	87.63%	$15,004	$2,119
87			$17,123		$17,123		$15,004	$2,119
88								
89		E391 - Office Furniture, Equipment	14,452	100.00%	14,452	87.63%	12,664	1,788
90			14,452		14,452		12,664	1,788
91								
92		E393 - Stores Equipment	29	100.00%	29	87.63%	25	4
93			29		29		25	4
94								
95		E394 - Tools, Shop, Garage Equipmnt	22,935	100.00%	22,935	87.63%	20,098	2,838
96			22,935		22,935		20,098	2,838
97								
98		E395 - Laboratory Equipment	184	100.00%	184	87.63%	161	23
99			184		184		161	23
100								
101		E397 - Communication Equipment	80,740	100.00%	80,740	87.63%	70,750	9,990
102			80,740		80,740		70,750	9,990
103								
104		E398 - Miscellaneous Equipment	(204)	100.00%	(204)	87.63%	(178)	(25)
105			(204)		(204)		(178)	(25)
106								
107		E399.1 - ARO Costs General Plt	1,804	100.00%	1,804	87.63%	1,581	223
108			1,804		1,804		1,581	223
109								
110		Sub-total General Plant	$137,062		$137,062		$120,103	$16,959
111								
112		**Total**	**$2,812,336**		**$2,812,336**		**$2,161,844**	**$650,492**

Line No.	Category	Account	(1) Reference	(2) FTY Amount
1	**Electric - Intangible Plant**	E303 - Misc Intangible Plant		($0)
2		Sub-total Electric - Intangible Plant		($0)
3				
4	**Electric - Transmission**	E350 - Land and Land Rights		$0
5		E352 - Structures and Improvements		123
6		E353 - Station Equipment		2,704
7		E354 - Towers and Fixtures		177
8		E355 - Poles and Fixtures		76
9		E356 - Overhead Conductors, Devices		1,462
10		E357 - Underground Conduit		850
11		E358 - Undergrnd Conductors, Devics		1,172
12		E359 - Roads and Trails		4
13		Sub-total Electric - Transmission	SUM L4 to L12	$6,569
14				
15	**Electric - Distribution**	E361 - Structures and Improvements		$1,110
16		E362 - Station Equipment		5,746
17		E364 - Poles, Towers and Fixtures		16,669
18		E365 - Overhead Conductors, Devices		19,073
19		E366 - Underground Conduit		4,267
20		E367 - Undergrnd Conductors, Devics		20,169
21		E368 - Line Transformers		897
22		E369 - Services		708
23		E370 - Meters		207
24		E373 - Street Lighting, Signal Systems		114
25		Sub-total Electric - Distribution	SUM L15 to L24	$68,960
26				
27	**Electric - General Plant**	E390 - Structures and Improvements		$95
28		E391 - Office Furniture, Equipment		60
29		E394 - Tools, Shop, Garage Equipmnt		14
30		E397 - Communication Equipment		556
31		E398 - Miscellaneous Equipment		93
32		Sub-total Electric - General Plant	SUM L27 to L31	$818
33				
34		**Total**	Lines 2+13+25+32	**$76,347**

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	FTY Expenses	(Lead)/Lag Days	Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			51.95	
4					
5	Expense Lag Days				
6	Payroll (Dist Only)		$168,294	13.58	$2,285,995
7	Pension Expense		4,396	(168.00)	(738,607)
8	Commodity Purchased - [A]		1,048,667	35.67	37,402,456
9	Commodity Purchased - [B]		8,615	12.50	107,692
10	PJM Transmission Purchased - By-passable		94,863	12.50	1,185,792
11	PJM Transmission Purchased - Non By-passable		94,454	12.50	1,180,674
12	Other Expenses		563,898	40.07	22,596,545
13	Sub-Total O&M	SUM L6 to L12	$1,983,188		$64,020,547
14					
15	Payment to Suppliers		$1,107,648	37.87	$41,950,771
16					
17	Total O&M and POR Payments	L13 + L15	$3,090,836		$105,971,318
18					
19	O&M Expense / POR Payment Lag Days			34.29	
20					
21	Net Lead/(Lag) Days	L3 - L19		17.66	
22					
23	Days in Current Year			365	
24					
25	Operating Expenses Per Day		$8,468		
26					
27	Working Capital for O&M Expense		$149,579		
28					
29	Average Prepayments		$8,636		
30	Accrued Taxes		$81,526		
31	Interest Payments		($17,451)		
32					
33	**Total Working Capital Requirement**	SUM L27 to L31	**$222,289**		
34					
35	Pro Forma O&M Expense		$2,031,256		
36	Uncollectible Expense		48,068		
37	Pro Forma Cash O&M Expense	L35 - L36	$1,983,188		

Line No.	Description	Reference	(1) Accounts Receivable Balance End of Month	(2) Total Monthly Billing Revenue	(3) A/R Turnover	(4) Days Lag
1	Annual Number of Days					365
2						
3	December		$402,842			
4	January		453,446	$378,637		
5	February		445,195	329,190		
6	March		411,718	303,032		
7	April		408,197	278,953		
8	May		340,718	260,453		
9	June		347,805	288,753		
10	July		409,252	373,500		
11	August		386,093	404,999		
12	September		398,390	381,298		
13	October		308,580	293,722		
14	November		285,129	267,091		
15	December		341,788	320,380		
16						
17	Total	SUM L3 to L15	$4,939,151	$3,880,008		
18						
19	Average A/R Balance		13			
20						
21	Factor		$379,935	$3,880,008	10.21	35.74
22						
23	Collection Days Lag					35.74
24						
25	Billing and Revenue Recording Days Lag					1.00
26						
27	Billing Lag (Average Period)	365 / 12. * 0.5				15.21
28						
29	**Total Revenue Lag Days**	L23 + L25 + L27				**51.95**

Line No.	Category	Description	Reference	Payment Date	Mid-point of Service Period	Expense Amount	(Lead)/Lag Days	Dollar Days
			(1)	(2)	(3)	(4)	(5)	(6)
1	PAYROLL	Union & Non-Union Payroll				$160,224		
2		Paid Twice Per Month					13.58	
3		Weighted Payroll Dollar Value						$2,176,372
4								
5		**Payroll Lag**	SUM L1 to L3			$160,224	**13.58**	$2,176,372
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2024	7/1/2024	$2,878	(168.00)	($483,504)
12								
13		Sub-total	SUM L7 to L11			$2,878		($483,504)
14								
15		**Lag Days for Pension Payment**					**(168.00)**	
16								
17	PURCHASE COMMODITY COSTS	**Payment Lag - Contract Purchases**					**35.67**	
18		**Payment Lag - Spot Market/PJM Purchases**					**12.50**	
19		**Payment Lag - Payment to Suppliers**					**37.87**	
20								
21								
22	OTHER O & M EXPENSES	January				$16,812		$651,478
23		April				26,471		1,077,737
24		July				25,711		1,175,140
25		October				22,699		769,982
26								
27		**Lag Days for Other Expenses**	SUM L22 to L25			$91,693	**40.07**	$3,674,337

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			(1)	(2)	(3)	(4)
Line No.	Months	Description	Number of CDs	Cash Disbursements	Dollar-Days	Expense Lag Days
1	January	Total Disbursements for Month	19,206	$337,934		
2		Total Disbursements for Expenses	1,354	$16,812	$651,478	38.75
3						
4	April	Total Disbursements for Month	33,541	$241,401		
5		Total Disbursements for Expenses	2,115	$26,471	$1,077,737	40.71
6						
7	July	Total Disbursements for Month	29,010	$256,674	-	
8		Total Disbursements for Expenses	1,842	$25,711	$1,175,140	45.70
9						
10	October	Total Disbursements for Month	22,765	$232,356	-	
11		Total Disbursements for Expenses	1,978	$22,699	$769,982	33.92
12	**TOTAL FOUR TEST MONTHS**					
13						
14	**Total Test Month Expense Disbursement**		7,289	$91,693	$3,674,337	**40.07**

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Line No.	Description	Description	Payment Date	Mid Point Date	Lead/(Lag) Payment Days	Total Payment Amount	Payment Percentage	Payment Amount	Weighted Dollar Days
			(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**FEDERAL INCOME TAX**	First Payment	4/15/2024	7/1/2024	77	$118,890	25.00%	$29,723	$2,288,641
2		Second Payment	6/17/2024	7/1/2024	14	118,890	25.00%	29,723	416,117
3		Third Payment	9/16/2024	7/1/2024	(77)	118,890	25.00%	29,723	(2,288,641)
4		Fourth Payment	12/16/2024	7/1/2024	(168)	118,890	25.00%	29,723	(4,993,399)
5		Sub-total FEDERAL INCOME TAX					100.00%	$118,890	($4,577,282)
6									
7	**STATE INCOME TAX**	First Payment	3/15/2024	7/1/2024	108	$12,742	25.00%	$3,186	$344,044
8		Second Payment	6/17/2024	7/1/2024	14	12,742	25.00%	3,186	44,598
9		Third Payment	9/16/2024	7/1/2024	(77)	12,742	25.00%	3,186	(245,291)
10		Fourth Payment	12/16/2024	7/1/2024	(168)	12,742	25.00%	3,186	(535,180)
11		Sub-total STATE INCOME TAX					100.00%	$12,742	($391,828)
12									
13	**PURTA**	First Payment	5/1/2024	7/1/2024	61	$5,690	100.00%	$5,690	$347,061
14		Subtotal PURTA					100.00%	$5,690	$347,061
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Sub-total PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/9/2024	7/1/2024	22	$4,800	100.00%	$4,800	$105,608
23		Second Payment							
24		Sub-total PA PROPERTY TAX					100.00%	$4,800	$105,608
25									
26	**GROSS RECEIPTS TAX**	First Payment	3/15/2024	7/1/2024	108	$168,117	100.00%	$168,117	$18,156,598
27		Sub-total GROSS RECEIPTS TAX					100.00%	$168,117	$18,156,598

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Total Payment Amount	Weighted Dollar Days	Payment Lead/(Lag) Days	Revenue Lag Days	Net Payment Lead/(Lag) Days	Net Payment Lead/(Lag) Dollars Days	Average Daily Amount for Working Capital
1	FEDERAL INCOME TAX	$118,890	($4,577,282)	(38.50)	51.95	13.45	$1,599,022	$4,381
2	STATE INCOME TAX	$12,742	($391,828)	(30.75)	51.95	21.20	$270,132	$740
3	PURTA	$5,690	$347,061	61.00	51.95	112.95	$642,630	$1,761
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$4,800	$105,608	22.00	51.95	73.95	$354,984	$973
6	GROSS RECEIPTS TAX	$168,117	$18,156,598	108.00	51.95	159.95	$26,890,181	$73,672

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Measures of Value at End of FTY		$7,948,351
2	Long-Term Debt Ratio		46.60%
3	Embedded Cost of Long-Term Debt		4.36%
4	Pro Forma Interest Expense	L1 * L2 * L3	$161,491
5	Days in Curent Year		366
6	Daily Amount	L4 / L5	$441
7	Days to Mid-Point of Interest Payments	L5 / 4	91.50
8	Less: Revenue Lag Days	C-4	51.95
9	Interest Payment Lag Days	L8 - L7	(39.55)
10	**Total Interest for Working Capital**	L6 * L9	**($17,451)**

Line No.	Description	Reference	EPRI Dues	EEI Dues	EAP Membership Dues	Prepaid Rents & Pole Attachments	PUC Assessment Electric	Land Leasing	Maintenance	IT License & Maintenance	Business Support Systems	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1	December					$331	$3,893	$194		$32	$217	$2,394	$0	$96	$448	$71	$327	$1,247	
2	January			$573		788	3,032			($0)	469	2,394	(18)	88	465	51	285	816	
3	February			521		745	2,425			$356	424	2,394	(35)	80	420	170	372	701	
4	March			469		558	1,819	188		$324	333	3,157	157	88	420	254	305	662	
5	April		$304	417	$237	392	1,213		244	$291	544	3,157	139	80	433	112	276	728	
6	May		203	365	138	212	606		195	$259	453	3,157	122	72	428	159	243	731	
7	June		203	313	118	170	0	181	195	$227	226	3,584	105	119	422	294	223	739	
8	July		203	261	99	641	5,155		195	$204	467	3,584	87	111	441	562	277	760	
9	August		203	208	79	453	4,495		195	$240	486	3,584	70	103	441	761	214	685	
10	September		101	156	59	624	5,779	175	195	$201	513	3,775	52	136	399	623	146	664	
11	October		101	104	39	469	5,205		195	$161	491	3,775	35	128	404	561	92	664	
12	November			52	20	284	4,630		195	$405	363	3,775	17	120	438	500	59	712	
13	December			0		234	4,055	168	195	$82	283	4,879	0	153	451	248	573	777	
14																			
15	Total	SUM L1 to L13	$1,319	$3,440	$788	$5,900	$42,307	$906	$1,804	$2,782	$5,270	$43,611	$731	$1,376	$5,610	$4,367	$3,392	$9,886	
16																			
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	67.41%	67.41%	67.41%	67.41%	74.50%	74.50%	74.50%	
18																			
19	Distribution Amount	L15 * L17	$1,319	$3,440	$788	$5,900	$42,307	$906	$1,804	$2,782	$5,270	$29,399	$493	$927	$3,782	$3,254	$2,527	$7,365	
20																			
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																			
23	Monthly Average	L19 / L21	$101	$265	$61	$454	$3,254	$70	$139	$214	$405	$2,261	$38	$71	$291	$250	$194	$567	
24																			
25	**Rate Case Amount**																		**$8,636**

Line No.	Description	(1) Midpoint of Prior Month Service Period to end of Month	(2) Payment Date Month after Service Period	(3) Additional Weekend or Holidays Extending Payment Date	(4) Lag Days	(5) Average
1	**Contract Purchases in FTY**					
2	January	15.50	19.00	3.00	37.50	
3	February	15.50	19.00	1.00	35.50	
4	March	14.50	19.00	1.00	34.50	
5	April	15.50	19.00	2.00	36.50	
6	May	15.00	19.00	1.00	35.00	
7	June	15.50	19.00	1.00	35.50	
8	July	15.00	19.00	2.00	36.00	
9	August	15.50	19.00	1.00	35.50	
10	September	15.50	19.00	1.00	35.50	
11	October	15.00	19.00	2.00	36.00	
12	November	15.50	19.00	1.00	35.50	
13	December	15.00	19.00	1.00	35.00	
14	**Payment Lag - Contract Purchases**					**35.67**
15						
16	**Spot Market Purchases in FTY and PJM Transmission Purchased**					
17		Service Period	Units	Service Period of Days	Lag Days	Total
18						
19	Service Period Weekly	Wed . to Tues.	Days	7.00		
20						
21	Days from Midpoint to End of Service				3.50	
22						
23	Payment Due on Friday of each Week				9.00	
24	**Payment Lag - Spot Market/PJM Purchases**					**12.50**
25						
26	**Payments to Suppliers**					
27		Payment Lag Days	Revenue Percentage	Weighted Lag Days	Lag Days	Total
28						
29	Residential	25.00	33%	8.33		
30	Nonresidential	20.00	67%	13.34		
31	Weighted Lag Days				21.67	
32						
33	Billing and Revenue Recording Days Lag				1.00	
34						
35	Billing Lag (Average Period)	365 / 12. * 0.5			15.21	
36						
37	Total POR Payment Lag Days	L31 + L33 + L35				**37.87**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - CIAC		($18,074)	100.00%	($18,074)	100.00%	($18,074)
2		ADIT - Common Plant		69,010	100.00%	69,010	63.22%	43,626
3		ADIT - Electric Common Plant		35,732	100.00%	35,732	82.17%	29,362
4		ADIT - Electric Distribution		619,210	100.00%	619,210	100.00%	619,210
5		ADIT - Corp. Alternative Minimum Tax		(60,332)	100.00%	(60,332)	100.00%	(60,332)
6		Sub-total	SUM L1 to L5	$645,546		$645,546		$613,793
7								
8	**FTY**	DIT - CIAC		($5,056)	100.00%	($5,056)	100.00%	($5,056)
9		DIT - Common Plant			100.00%		63.22%	
10		DIT - Electric Common Plant			100.00%		82.17%	
11		DIT - Electric Distribution		35,217	100.00%	35,217	100.00%	35,217
12		DIT - Corp. Alternative Minimum Tax		(48,211)	100.00%	(48,211)	100.00%	(48,211)
13		Sub-total	SUM L8 to L12	($18,050)		($18,050)		($18,050)
14								
15		**Total**	L6 + L13 + L20	**$627,496**		**$627,496**		**$595,742**

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Residential	Non-Residential	Total
1	December		$18,802	$31,587	$50,388
2	January		18,976	32,487	51,463
3	February		19,166	33,197	52,363
4	March		19,446	33,844	53,290
5	April		20,077	34,307	54,384
6	May		20,877	35,117	55,994
7	June		21,538	35,642	57,179
8	July		22,060	36,988	59,048
9	August		22,549	38,022	60,571
10	September		22,772	38,782	61,555
11	October		23,058	39,358	62,416
12	November		23,276	39,646	62,922
13	December		23,215	39,988	63,203
14					
15	Total	SUM L1 to L13	$275,812	$468,965	$744,777
16					
17	Average Monthly Balance	L15 / 13	$21,216	$36,074	$57,291
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$21,216
21	Small C&I				30,886
22	Large C&I				5,183
23	Other				5
24					
25	**Total**	SUM L20 to L23			**$57,291**

Line No.	Category	Account	Reference	FTY Amount	Allocated to Non Jurisdiction	Allocated to Jurisdiction
			(1)	(2)	(3)	(4)
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$221	$456
4						
5		E303 - Misc Intangible Plant		$318,316	$94,761	$223,555
6						
7		E389 - Land and Land Rights		$6,783	$2,211	$4,573
8						
9		E390 - Structures and Improvements		$409,398	$133,417	$275,981
10		E391 - Office Furniture, Equipment		76,600	24,963	51,637
11		E392 - Transportation Equipment		213,002	69,414	143,588
12		E393 - Stores Equipment		1,255	409	846
13		E394 - Tools, Shop, Garage Equipmnt		2,348	765	1,583
14		E396 - Power Operated Equipment		185	60	125
15		E397 - Communication Equipment		147,623	48,108	99,515
16		E398 - Miscellaneous Equipment		1,175	383	792
17		E399 - Other Tangible Property				
18		E399.1 - ARO Costs General Plant		916	299	618
19		Sub Total - General Plant	SUM L9 to L18	$852,502	$277,818	$574,683
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,178,278	$375,011	$803,267
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$120,854	$38,611	$82,243
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$70,146	$22,860	$47,286
31		E391 - Office Furniture, Equipment		28,248	9,206	19,042
32		E392 - Transportation Equipment		102,106	33,275	68,831
33		E393 - Stores Equipment		309	101	208
34		E394 - Tools, Shop, Garage Equipmnt		898	292	605
35		E396 - Power Operated Equipment		185	60	125
36		E397 - Communication Equipment		44,465	14,490	29,974
37		E398 - Miscellaneous Equipment		906	295	611
38		E399 - Other Tangible Property				
39		E399.1 - ARO Costs General Plant		(358)	(117)	(242)
40		Sub Total - General Plant	SUM L30 to L39	$246,904	$80,463	$166,442
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$367,758	$119,074	$248,685
42						
43		Net Common Plant	L20 - L41	$810,519	$255,937	$554,582
44						
45						
46		Common Plant in Service to Utility	L20	$1,178,278	$375,011	$803,267
47		Common Plant Accum Depreciation to Utility	L41	367,758	119,074	248,685
48		Net Common Plant to Utility	L46 - L47	$810,519	$255,937	$554,582

		(1)	(2)
Line No.	Description	Reference	Total
1	HTY 13-Month Average		
2	December		$2,662
3	January		2,509
4	February		2,978
5	March		3,239
6	April		3,066
7	May		2,900
8	June		2,423
9	July		2,393
10	August		2,049
11	September		3,859
12	October		3,861
13	November		2,764
14	December		2,855
15			
16	13-Month Total	SUM L2 to L14	$37,557
17			
18			
19	**Average Monthly Balance**	L16 / 13	**$2,889**

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Materials & Supplies	Undistributed Stores Expense	Total
1	HTY 13-Month Average				
2	December		$29,564	($0)	$29,564
3	January		30,031	(191)	29,840
4	February		28,319	(372)	27,947
5	March		26,573	(1,490)	25,083
6	April		26,183	(1,111)	25,072
7	May		26,568	(1,460)	25,108
8	June		27,575	(1,693)	25,882
9	July		28,584	(1,197)	27,387
10	August		33,678	(1,126)	32,553
11	September		34,598	(1,077)	33,522
12	October		34,602	(660)	33,943
13	November		36,708	(686)	36,023
14	December		39,019	0	39,019
15					
16	Total	SUM L2 to L14	$402,003	($11,061)	$390,942
17					
18	Distribution Expense Allocation Factor		100.00%	67.41%	
19					
20	Allocation to Distribution	L16 * L18	$402,003	($7,457)	
21					
22	**Average Monthly Balance**	L20 / 13	$30,923	($574)	**$30,350**

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				(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount	
1	**HTY**	ADIT - Distribution		$288,276	100.00%	$288,276	100.00%	$288,276	
2		ADIT - CIAC			100.00%		100.00%		
3		Sub-total HTY	L1 + L2	288,276		288,276		288,276	
4									
5	**FTY**	DIT - Distribution		($7,023)	100.00%	($7,023)	100.00%	($7,023)	
6		DIT - CIAC			100.00%		100.00%		
7		Sub-total FTY	L5 + L6	(7,023)		(7,023)		(7,023)	
8									
9		**Total**	L3 + L7 + L11	$281,253		$281,253		$281,253	

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Line No.	Category	Description	Reference	(1) Pro Forma Adjusted at Present Rates	(2) Proposed Rate Increase	(3) Adjusted Amounts with Proposed Rate Increase
1	**Operating Revenues**	Residential		$1,633,045		$1,633,045
2		Residential - House Heating		361,503		361,503
3		C & I Small		424,227		424,227
4		C & I Large		234,998		234,998
5		Railroads & Railways		7,218		7,218
6		Street Lighting		22,731		22,731
7		Intercompany				
8		Transmission - All Classes		202,352		202,352
9		Forfeited Discounts		11,428	$995	12,423
10		Miscellaneous Service Revenues		3,684		3,684
11		Rent For Electric Property		22,021		22,021
12		Other Electric Revenues		9,270		9,270
13		Revenue Increase			$356,463	356,463
14		Total Operating Revenues	SUM L1 to L13	$2,932,477	$357,459	$3,289,936
15						
16	**Operating Expenses**	Power Supply		$1,057,282		$1,057,282
17		Transmission Expense		189,317		189,317
18		Distribution Expense		425,355		425,355
19		Customer Accounts Expense		158,932	$3,461	162,392
20		Customer Service and Information Expense		20,605		20,605
21		Sales Expense		412		412
22		Administrative & General		179,353	854	180,208
23		Sub-total O&M Expense	SUM L16 to L22	$2,031,256	$4,315	$2,035,571
24						
25		Depreciation & Amortization Expense		$311,601		$311,601
26		Amortization of Regulatory Expense		10,749		10,749
27		Taxes Other Than Income Taxes - Other		$193,432	$21,031	$214,464
28		Total Operating Expenses	SUM L23 to L27	$2,547,038	$25,346	$2,572,384
29						
30	**Net Operating Income - BIT**		L14 - L28	**$385,439**	**$332,112**	**$717,551**

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			(1)	(2)	(3)	(4)
Line No.	Category	Description	Reference	FTY Amount Pre Adjustments	Adjustments Sub-Total	Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential		$1,657,562	($24,517)	$1,633,045
2		Residential - House Heating		366,779	(5,276)	361,503
3		C & I Small		456,183	(31,956)	424,227
4		C & I Large		270,165	(35,166)	234,998
5		Railroads & Railways		8,345	(1,127)	7,218
6		Street Lighting		23,219	(488)	22,731
7		Intercompany				
8		Transmission - All Classes		202,352		202,352
9		Forfeited Discounts		11,428		11,428
10		Miscellaneous Service Revenues		3,684		3,684
11		Rent For Electric Property		22,021		22,021
12		Other Electric Revenues		9,270		9,270
13		Revenue Increase				
14		Total Operating Revenues	SUM L1 to L13	$3,031,007	($98,530)	$2,932,477
15						
16	**Operating Expenses**	Power Supply		$1,057,282		$1,057,282
17		Transmission Expense		189,317		189,317
18		Distribution Expense		405,275	$20,080	425,355
19		Customer Accounts Expense		142,641	16,291	158,932
20		Customer Service and Information Expense		111,218	(90,613)	20,605
21		Sales Expense		400	11	412
22		Administrative & General		169,171	10,182	179,353
23		Sub-total O&M Expense	SUM L16 to L22	$2,075,306	($44,050)	$2,031,256
24						
25		Depreciation & Amortization Expense		$282,149	$29,452	$311,601
26		Amortization of Regulatory Expense		11,196	(448)	10,749
27		Taxes Other Than Income Taxes - Other		199,187	(5,754)	193,432
28		Total Operating Expenses	SUM L23 to L27	$2,567,838	($20,800)	$2,547,038
29						
30	**Net Operating Income - BIT**		L14 - L28	**$463,169**	**($77,730)**	**$385,439**

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Line No.	Category	Description	Description	(1) FTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act 129 Lost Revenue	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E OPEN	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization
1	**Operating Revenues**	Residential	Elec Cost	$726,764							
2			Cust & Dist	930,799	1,305	(1,498)	(1,883)	(22,941)		501	
3			Sub-total Residential	$1,657,562	$1,305	($1,498)	($1,883)	($22,941)		$501	
4											
5		Residential - House Heating	Elec Cost	$188,794							
6			Cust & Dist	177,985	969	(184)	(394)	(5,815)		147	
7			Sub-total Residential - House Heating	$366,779	$969	($184)	($394)	($5,815)		$147	
8											
9		C & I Small	Elec Cost	$160,260							
10			Cust & Dist	295,923	618		(1,138)	(31,587)		152	
11			Sub-total C & I Small	$456,183	$618		($1,138)	($31,587)		$152	
12											
13		C & I Large	Elec Cost	$52,012							
14			Cust & Dist	218,153			(791)	(34,500)		125	
15			Sub-total C & I Large	$270,165			($791)	($34,500)		$125	
16											
17		Railroads & Railways	Cust & Dist	$8,345				($1,127)			
18			Sub-total Railroads & Railways	$8,345				($1,127)			
19											
20		Street Lighting	Elec Cost	$845							
21			Cust & Dist	22,374				(488)			
22			Sub-total Street Lighting	$23,219				($488)			
23											
24		Intercompany	Elec Cost								
25			Cust & Dist								
26			Sub-total Interdepartmental								
27											
28		Transmission - All Classes	Transmission - All Classes	$202,352							
29			Sub-total Transmission - All Classes	$202,352							
30											
31		Forfeited Discounts	Forfeited Discounts	$11,428							
32			Sub-total Forfeited Discounts	$11,428							
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues	$3,684							
35			Sub-total Miscellaneous Service Revenues	$3,684							
36											
37		Rent For Electric Property	Rent For Electric Property	$22,021							
38			Sub-total Rent For Electric Property	$22,021							
39											
40		Other Electric Revenues	Other Electric Revenues	$9,270							
41			Sub-total Other Electric Revenues	$9,270							
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**	**$3,031,007**	**$2,892**	**($1,682)**	**($4,207)**	**($96,458)**		**$925**	
47											
48	**Operating Expenses**	Power Supply	Purchased Power	$1,057,282							

Line No.	Category	Description	Description	FTY Amount Pre Adjustments	(1) D-5A Revenue Annualization	(2) D-5B CAP Revenue Credits and Adjustments	(3) D-5C Act 129 Lost Revenue	(4) D-5D Energy Efficiency Program Cost Recovery	(5) D-5E OPEN	(6) D-5F Leap Year Adjustment	(7) D-5G Weather Normalization	(8)
49			Sub-total Power Supply	$1,057,282								
50												
51		Transmission Expense	Operation & Supervision									
52			Load Dispatching									
53			Scheduling, System Control & Dispatch	95,200								
54			Transmission Service Studies									
55			Generation Service Studies									
56			Reliability, Planning & Standard Development	94,118								
57			Station Expense									
58			Overhead Lines									
59			Underground Lines Expense									
60			Miscellaneous Expense									
61			Rents									
62			Maintenance of Structures									
63			Maintenance of Computer Hardware									
64			Maintenance of Computer Software									
65			Maintenance of Communication Equipment									
66			Maintenance of Station Equipment									
67			Maintenance of Overhead Lines									
68			Maintenance of Underground Lines									
69			Maintenance of Misc Transmission Plant									
70			Sub-total Transmission Expense	189,317								
71												
72		Distribution Expense	Operation & Supervision	$1,216								
73			Load Dispatching									
74			Station Expense	767								
75			Overhead Lines Expenses	16,441								
76			Underground Lines Expense	13,832								
77			Meter Expenses	7,433								
78			Customer Installations Expense	13,661								
79			Miscellaneous Expense	85,996								
80			Rents	3,438								
81			Maintenance of Structures	6,274								
82			Maintenance of Station Equipment	17,567								
83			Maintenance of Overhead Lines	178,544								
84			Maintenance of Underground Lines	36,485								
85			Maintenance of Line Transformers	2,266								
86			Maintenance of Street Lighting & Signal Systems	1,858								
87			Maintenance of Misc. Distribution	19,498								
88			Sub-total Distribution Expense	$405,275								
89												
90		Customer Accounts	Supervision									
91			Meter Reading	$916								
92			Customer Records and Collection	101,136								
93			Uncollectible Accounts.	37,131								
94			Miscellaneous Customer Accounts Expenses.	3,458								
95			Sub-total Total Customer Accounts	$142,641								
96												

Line No.	Category	Description	Description	FTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Act 129 Lost Revenue	D-5D Energy Efficiency Program Cost Recovery	D-5E OPEN	D-5F Leap Year Adjustment	D-5G Weather Normalization
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
97		Customer Service and Information	Customer Assistance	$108,961				($90,706)			
98			Informational & Instructional	1,320							
99			Miscellaneous Customer & Informational	937							
100			Sub-total Customer Service & Information	$111,218				($90,706)			
101											
102		Sales	Demonstrating & Selling	$400							
103			Miscellaneous Sales								
104			Sub-total Sales	$400							
105											
106		Administrative & General	Administrative and General Salaries	$28,705							
107			Office Supplies and Expenses	4,324							
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed	85,009							
110			Property Insurance	717							
111			Injuries & Damages	11,108							
112			Employee Pensions and Benefits	21,231							
113			Regulatory Commission Expenses	8,845							
114			Duplicate Charges-Credit	(997)							
115			Miscellaneous General Expenses	2,468							
116			Maintenance of General Plant	7,763							
117			Sub-total Administrative & General	$169,171							
118											
119			**Total O&M Expense**	$2,075,306				($90,706)			
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$282,149							
122			Sub-total Depreciation & Amortization Expense	$282,149							
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense	$11,196							
125			Sub-total Amortization of Regulatory Expense	$11,196							
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$199,187							
128			Sub-total Taxes Other Than Income Taxes - Other	$199,187							
129											
130			**Total Operating Expenses**	**$2,567,838**				**($90,706)**			
131											
132	**Net Operating Income Before Income Tax**			**$463,169**	**$2,892**	**($1,682)**	**($4,207)**	**($5,752)**		**$925**	

Line No.	Category	Description	Description	(9) D-6 Salary & Wages	(10) D-7 Rate Case Expense	(11) D-8 Adjustments for Employee Benefits	(12) D-9 Adjustments for Pension	(13) D-10 Uncollectible Accounts	(14) D-11 IIJA Reg Asset	(15) D-12 Customer Deposit Interest	(16) D-13 Storm
1	**Operating Revenues**	Residential	Elec Cost								
2			Cust & Dist								
3			Sub-total Residential								
4											
5		Residential - House Heating	Elec Cost								
6			Cust & Dist								
7			Sub-total Residential - House Heating								
8											
9		C & I Small	Elec Cost								
10			Cust & Dist								
11			Sub-total C & I Small								
12											
13		C & I Large	Elec Cost								
14			Cust & Dist								
15			Sub-total C & I Large								
16											
17		Railroads & Railways	Cust & Dist								
18			Sub-total Railroads & Railways								
19											
20		Street Lighting	Elec Cost								
21			Cust & Dist								
22			Sub-total Street Lighting								
23											
24		Intercompany	Elec Cost								
25			Cust & Dist								
26			Sub-total Interdepartmental								
27											
28		Transmission - All Classes	Transmission - All Classes								
29			Sub-total Transmission - All Classes								
30											
31		Forfeited Discounts	Forfeited Discounts								
32			Sub-total Forfeited Discounts								
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues								
35			Sub-total Miscellaneous Service Revenues								
36											
37		Rent For Electric Property	Rent For Electric Property								
38			Sub-total Rent For Electric Property								
39											
40		Other Electric Revenues	Other Electric Revenues								
41			Sub-total Other Electric Revenues								
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**								
47											
48	**Operating Expenses**	Power Supply	Purchased Power								

Line No.	Category	Description	Description	(9) D-6 Salary & Wages	(10) D-7 Rate Case Expense	(11) D-8 Adjustments for Employee Benefits	(12) D-9 Adjustments for Pension	(13) D-10 Uncollectible Accounts	(14) D-11 IIJA Reg Asset	(15) D-12 Customer Deposit Interest	(16) D-13 Storm
49			Sub-total Power Supply								
50											
51		Transmission Expense	Operation & Supervision								
52			Load Dispatching								
53			Scheduling, System Control & Dispatch								
54			Transmission Service Studies								
55			Generation Service Studies								
56			Reliability, Planning & Standard Development								
57			Station Expense								
58			Overhead Lines								
59			Underground Lines Expense								
60			Miscellaneous Expense								
61			Rents								
62			Maintenance of Structures								
63			Maintenance of Computer Hardware								
64			Maintenance of Computer Software								
65			Maintenance of Communication Equipment								
66			Maintenance of Station Equipment								
67			Maintenance of Overhead Lines								
68			Maintenance of Underground Lines								
69			Maintenance of Misc Transmission Plant								
70			Sub-total Transmission Expense								
71											
72		Distribution Expense	Operation & Supervision	$50							
73			Load Dispatching								
74			Station Expense	3							
75			Overhead Lines Expenses	149							
76			Underground Lines Expense	123							
77			Meter Expenses	127							
78			Customer Installations Expense	309							
79			Miscellaneous Expense	348							
80			Rents								
81			Maintenance of Structures	65							
82			Maintenance of Station Equipment	426							
83			Maintenance of Overhead Lines	2,089							15,346
84			Maintenance of Underground Lines	815							
85			Maintenance of Line Transformers	24							
86			Maintenance of Street Lighting & Signal Systems	5							
87			Maintenance of Misc. Distribution	203							
88			Sub-total Distribution Expense	$4,734							$15,346
89											
90		Customer Accounts	Supervision								
91			Meter Reading	0							
92			Customer Records and Collection	1,786							
93			Uncollectible Accounts.					10,937			
94			Miscellaneous Customer Accounts Expenses.	38					3,572		
95			Sub-total Total Customer Accounts	$1,824				$10,937	$3,572		
96											

Line No.	Category	Description	Description	D-6 Salary & Wages (9)	D-7 Rate Case Expense (10)	D-8 Adjustments for Employee Benefits (11)	D-9 Adjustments for Pension (12)	D-10 Uncollectible Accounts (13)	D-11 IIJA Reg Asset (14)	D-12 Customer Deposit Interest (15)	D-13 Storm (16)
97		Customer Service and Information	Customer Assistance	$82							
98			Informational & Instructional								
99			Miscellaneous Customer & Informational	11							
100			Sub-total Customer Service & Information	$93							
101											
102		Sales	Demonstrating & Selling	$11							
103			Miscellaneous Sales								
104			Sub-total Sales	$11							
105											
106		Administrative & General	Administrative and General Salaries	$1,251							
107			Office Supplies and Expenses								
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed								
110			Property Insurance								
111			Injuries & Damages	88							
112			Employee Pensions and Benefits	2		414	6,160				
113			Regulatory Commission Expenses		1,200						
114			Duplicate Charges-Credit								
115			Miscellaneous General Expenses	3							
116			Maintenance of General Plant	65							
117			Sub-total Administrative & General	$1,409	$1,200	$414	$6,160				
118											
119			**Total O&M Expense**	$8,070	$1,200	$414	$6,160	$10,937		$3,572	$15,346
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense								
122			Sub-total Depreciation & Amortization Expense								
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense						($448)		
125			Sub-total Amortization of Regulatory Expense						($448)		
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other								
128			Sub-total Taxes Other Than Income Taxes - Other								
129											
130			**Total Operating Expenses**	**$8,070**	**$1,200**	**$414**	**$6,160**	**$10,937**	**($448)**	**$3,572**	**$15,346**
131											
132	**Net Operating Income Before Income Tax**			**($8,070)**	**($1,200)**	**($414)**	**($6,160)**	**($10,937)**	**$448**	**($3,572)**	**($15,346)**

Line No.	Category	Description	Description	D-14 Other Adjustments	D-15 OPEN	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
				(17)	(18)	(19)	(20)	(21)	(22)
1	**Operating Revenues**	Residential	Elec Cost						$726,764
2			Cust & Dist					(24,517)	906,282
3			Sub-total Residential					($24,517)	$1,633,045
4									
5		Residential - House Heating	Elec Cost						$188,794
6			Cust & Dist					(5,276)	172,709
7			Sub-total Residential - House Heating					($5,276)	$361,503
8									
9		C & I Small	Elec Cost						$160,260
10			Cust & Dist					(31,956)	263,968
11			Sub-total C & I Small					($31,956)	$424,227
12									
13		C & I Large	Elec Cost						$52,012
14			Cust & Dist					(35,166)	182,986
15			Sub-total C & I Large					($35,166)	$234,998
16									
17		Railroads & Railways	Cust & Dist					($1,127)	$7,218
18			Sub-total Railroads & Railways					($1,127)	$7,218
19									
20		Street Lighting	Elec Cost						$845
21			Cust & Dist					(488)	21,886
22			Sub-total Street Lighting					($488)	$22,731
23									
24		Intercompany	Elec Cost						
25			Cust & Dist						
26			Sub-total Interdepartmental						
27									
28		Transmission - All Classes	Transmission - All Classes						$202,352
29			Sub-total Transmission - All Classes						$202,352
30									
31		Forfeited Discounts	Forfeited Discounts						$11,428
32			Sub-total Forfeited Discounts						$11,428
33									
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues						$3,684
35			Sub-total Miscellaneous Service Revenues						$3,684
36									
37		Rent For Electric Property	Rent For Electric Property						$22,021
38			Sub-total Rent For Electric Property						$22,021
39									
40		Other Electric Revenues	Other Electric Revenues						$9,270
41			Sub-total Other Electric Revenues						$9,270
42									
43		Revenue Increase	Revenue Increase						
44			Sub-total Revenue Increase						
45									
46			**Total Operating Revenues**					**($98,530)**	**$2,932,477**
47									
48	**Operating Expenses**	Power Supply	Purchased Power						$1,057,282

Line No.	Category	Description	Description	D-14 Other Adjustments	D-15 OPEN	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
				(17)	(18)	(19)	(20)	(21)	(22)
49			Sub-total Power Supply						$1,057,282
50									
51		Transmission Expense	Operation & Supervision						
52			Load Dispatching						
53			Scheduling, System Control & Dispatch						95,200
54			Transmission Service Studies						
55			Generation Service Studies						
56			Reliability, Planning & Standard Development						94,118
57			Station Expense						
58			Overhead Lines						
59			Underground Lines Expense						
60			Miscellaneous Expense						
61			Rents						
62			Maintenance of Structures						
63			Maintenance of Computer Hardware						
64			Maintenance of Computer Software						
65			Maintenance of Communication Equipment						
66			Maintenance of Station Equipment						
67			Maintenance of Overhead Lines						
68			Maintenance of Underground Lines						
69			Maintenance of Misc Transmission Plant						
70			Sub-total Transmission Expense						189,317
71									
72		Distribution Expense	Operation & Supervision					$50	$1,265
73			Load Dispatching						
74			Station Expense					3	769
75			Overhead Lines Expenses					149	16,590
76			Underground Lines Expense					123	13,954
77			Meter Expenses					127	7,561
78			Customer Installations Expense					309	13,970
79			Miscellaneous Expense					348	86,343
80			Rents						3,438
81			Maintenance of Structures					65	6,339
82			Maintenance of Station Equipment					426	17,993
83			Maintenance of Overhead Lines					17,435	195,979
84			Maintenance of Underground Lines					815	37,300
85			Maintenance of Line Transformers					24	2,290
86			Maintenance of Street Lighting & Signal Systems					5	1,863
87			Maintenance of Misc. Distribution					203	19,700
88			Sub-total Distribution Expense					$20,080	$425,355
89									
90		Customer Accounts	Supervision						
91			Meter Reading					$0	$916
92			Customer Records and Collection					1,786	102,922
93			Uncollectible Accounts.					10,937	48,068
94			Miscellaneous Customer Accounts Expenses.	(43)				3,568	7,026
95			Sub-total Total Customer Accounts	($43)				$16,291	$158,932
96									

Line No.	Category	Description	Description	(17) D-14 Other Adjustments	(18) D-15 OPEN	(19) D-16 Taxes Other Than Income	(20) D-17 Depreciation Annualization	(21) Adjustments Sub-total	(22) Pro Forma Adjusted at Present Rates
97		Customer Service and Information	Customer Assistance					($90,624)	$18,337
98			Informational & Instructional						1,320
99			Miscellaneous Customer & Informational					11	947
100			Sub-total Customer Service & Information					($90,613)	$20,605
101									
102		Sales	Demonstrating & Selling					$11	$412
103			Miscellaneous Sales						
104			Sub-total Sales					$11	$412
105									
106		Administrative & General	Administrative and General Salaries					$1,251	$29,956
107			Office Supplies and Expenses						4,324
108			Administrative Expenses Transferred-Credit						
109			Outside Service Employed						85,009
110			Property Insurance						717
111			Injuries & Damages					88	11,196
112			Employee Pensions and Benefits					6,575	27,805
113			Regulatory Commission Expenses					1,200	10,045
114			Duplicate Charges-Credit						(997)
115			Miscellaneous General Expenses	1,000				1,003	3,471
116			Maintenance of General Plant					65	7,828
117			Sub-total Administrative & General	$1,000				$10,182	$179,353
118									
119			**Total O&M Expense**	$957				($44,050)	$2,031,256
120									
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense				$29,452	$29,452	$311,601
122			Sub-total Depreciation & Amortization Expense				$29,452	$29,452	$311,601
123									
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense					($448)	$10,749
125			Sub-total Amortization of Regulatory Expense					($448)	$10,749
126									
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other			($5,754)		($5,754)	$193,432
128			Sub-total Taxes Other Than Income Taxes - Other			($5,754)		($5,754)	$193,432
129									
130			**Total Operating Expenses**	**$957**		**($5,754)**	**$29,452**	**($20,800)**	**$2,547,038**
131									
132	**Net Operating Income Before Income Tax**			**($957)**		**$5,754**	**($29,452)**	**($77,730)**	**$385,439**

Line No.	Category	Description	Account	(1) FTY Amount Pre Adjustments	(2) D-5D Energy Efficiency Program Expense	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 IIJA Reg Asset
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.	$1,057,282							
2			Sub-total Power Supply	$1,057,282							
3											
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision								
5			561.0 Load Dispatching								
6			561.4 Scheduling, System Control & Dispatch	95,200							
7			561.6 Transmission Service Studies								
8			561.7 Generation Service Studies								
9			561.8 Reliability, Planning & Standard Development	94,118							
10			562.0 Station Expense								
11			563.0 Overhead Lines								
12			564.0 Underground Lines Expense								
13			566.0 Miscellaneous Expense								
14			567.0 Rents								
15			Sub-total Transmission Operations	189,317							
16											
17		**Transmission Maintenance**	569.0 Maintenance of Structures								
18			569.1 Maintenance of Computer Hardware								
19			569.2 Maintenance of Computer Software								
20			569.3 Maintenance of Communication Equipment								
21			570.0 Maintenance of Station Equipment								
22			571.0 Maintenance of Overhead Lines								
23			572.0 Maintenance of Underground Lines								
24			573.0 Maintenance of Misc Transmission Plant								
25			Sub-total Transmission Maintenance								
26											
27			Sub-total TRANSMISSION EXPENSE	189,317							
28											
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision	$1,216	$50						
30			581.0 Load Dispatching								
31			582.0 Station Expense	767	3						
32			583.0 Overhead Lines Expenses	16,441	149						
33			584.0 Underground Lines Expense	13,832	123						
34			586.0 Meter Expenses	7,433	127						
35			587.0 Customer Installations Expense	13,661	309						
36			588.0 Miscellaneous Expense	85,996	348						
37			589.0 Rents	3,438							
38			Sub-total Distribution Operations	$142,784	$1,107						
39											
40		**Distribution Maintenance**	591.0 Maintenance of Structures	$6,274	$65						
41			592.0 Maintenance of Station Equipment	17,567	426						
42			593.0 Maintenance of Overhead Lines	178,544	2,089						
43			594.0 Maintenance of Underground Lines	36,485	815						
44			595.0 Maintenance of Line Transformers	2,266	24						
45			596.0 Maintenance of Street Lighting & Signal Systems	1,858	5						
46			598.0 Maintenance of Misc. Distribution	19,498	203						
47			Sub-total Distribution Maintenance	$262,492	$3,626						
48											

					(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Category	Description	Account		FTY Amount Pre Adjustments	D-5D Energy Efficiency Program Expense	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 IIJA Reg Asset
49			Sub-total DISTRIBUTION EXPENSE		$405,275		$4,734					
50												
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision									
52			902.0 Meter Reading		$916		0					
53			903.0 Customer Records and Collection		101,136		1,786					
54			904.0 Uncollectible Accounts		37,131						10,937	
55			905.0 Miscellaneous Customer Accounts Expenses.		3,458		38					
56			Sub-total Customer Accounts		$142,641		$1,824				$10,937	
57												
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance		$108,961	($90,706)	$82					
59			909.0 Informational & Instructional		1,320							
60			910.0 Miscellaneous Customer & Informational		937		11					
61			Sub-total Customer Service & Information		$111,218	($90,706)	$93					
62												
63	**SALES**	**Sales**	912.0 Demonstrating & Selling		$400		$11					
64			916.0 Miscellaneous Sales									
65			Sub-total Sales		$400		$11					
66												
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries		$28,705		$1,251					
68			921.0 Office Supplies and Expenses		4,324							
69			922.0 Administrative Expenses Transferred-Credit									
70			923.0 Outside Service Employed		85,009							
71			924.0 Property Insurance		717							
72			925.0 Injuries & Damages		11,108		88					
73			926.0 Employee Pensions and Benefits		21,231		2		414	6,160		
74			928.0 Regulatory Commission Expenses		8,845			1,200				
75			929.0 Duplicate Charges-Credit		(997)							
76			930.2 Miscellaneous General Expenses		2,468		3					
77			Sub-total A&G Operations		$161,408		$1,344	$1,200	$414	$6,160		
78												
79		A&G Maintenance	935.0 Maintenance of General Plant		$7,763		$65					
80												
81			Sub-total ADMINISTRATION & GENERAL		$169,171		$1,409	$1,200	$414	$6,160		
82												
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.		$234,720							
84			404.0 Amort. Of Limited-Term Electric Plant.		47,429							
85			Sub-total Depreciation & Amortization Expense		$282,149							
86												
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.		$11,196							($448)
88			Sub-total Amortization of Regulatory Expense		$11,196							($448)
89												
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.		$199,187							
91			Sub-total Taxes Other Than Income Taxes - Other		$199,187							
92												
93			**Total**		**$2,567,838**	**($90,706)**	**$8,070**	**$1,200**	**$414**	**$6,160**	**$10,937**	**($448)**

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 Storm	D-14 Other Adjustments	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.								$1,057,282
2			Sub-total Power Supply								$1,057,282
3											
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision								
5			561.0 Load Dispatching								
6			561.4 Scheduling, System Control & Dispatch								95,200
7			561.6 Transmission Service Studies								
8			561.7 Generation Service Studies								
9			561.8 Reliability, Planning & Standard Development								94,118
10			562.0 Station Expense								
11			563.0 Overhead Lines								
12			564.0 Underground Lines Expense								
13			566.0 Miscellaneous Expense								
14			567.0 Rents								
15			Sub-total Transmission Operations								189,317
16											
17		**Transmission Maintenance**	569.0 Maintenance of Structures								
18			569.1 Maintenance of Computer Hardware								
19			569.2 Maintenance of Computer Software								
20			569.3 Maintenance of Communication Equipment								
21			570.0 Maintenance of Station Equipment								
22			571.0 Maintenance of Overhead Lines								
23			572.0 Maintenance of Underground Lines								
24			573.0 Maintenance of Misc Transmission Plant								
25			Sub-total Transmission Maintenance								
26											
27			Sub-total TRANSMISSION EXPENSE								189,317
28											
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision							$50	$1,265
30			581.0 Load Dispatching								
31			582.0 Station Expense							$3	$769
32			583.0 Overhead Lines Expenses							$149	$16,590
33			584.0 Underground Lines Expense							$123	$13,954
34			586.0 Meter Expenses							$127	$7,561
35			587.0 Customer Installations Expense							$309	$13,970
36			588.0 Miscellaneous Expense							$348	$86,343
37			589.0 Rents								$3,438
38			Sub-total Distribution Operations							$1,107	$143,891
39											
40		**Distribution Maintenance**	591.0 Maintenance of Structures							$65	$6,339
41			592.0 Maintenance of Station Equipment							426	17,993
42			593.0 Maintenance of Overhead Lines		15,346					17,435	195,979
43			594.0 Maintenance of Underground Lines							815	37,300
44			595.0 Maintenance of Line Transformers							24	2,290
45			596.0 Maintenance of Street Lighting & Signal Systems							5	1,863
46			598.0 Maintenance of Misc. Distribution							203	19,700
47			Sub-total Distribution Maintenance		$15,346					$18,972	$281,464
48											

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 Storm	D-14 Other Adjustments	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
49			Sub-total DISTRIBUTION EXPENSE		$15,346					$20,080	$425,355
50											
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision								
52			902.0 Meter Reading							$0	$916
53			903.0 Customer Records and Collection							$1,786	102,922
54			904.0 Uncollectible Accounts							10,937	48,068
55			905.0 Miscellaneous Customer Accounts Expenses.	3,572		(43)				3,568	7,026
56			Sub-total Customer Accounts	$3,572		($43)				$16,291	$158,932
57											
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance							($90,624)	$18,337
59			909.0 Informational & Instructional								1,320
60			910.0 Miscellaneous Customer & Informational							11	947
61			Sub-total Customer Service & Information							($90,613)	$20,605
62											
63	**SALES**	**Sales**	912.0 Demonstrating & Selling							$11	$412
64			916.0 Miscellaneous Sales								
65			Sub-total Sales							$11	$412
66											
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries							$1,251	$29,956
68			921.0 Office Supplies and Expenses								4,324
69			922.0 Administrative Expenses Transferred-Credit								
70			923.0 Outside Service Employed								85,009
71			924.0 Property Insurance								717
72			925.0 Injuries & Damages							88	11,196
73			926.0 Employee Pensions and Benefits							6,575	27,805
74			928.0 Regulatory Commission Expenses							1,200	10,045
75			929.0 Duplicate Charges-Credit								(997)
76			930.2 Miscellaneous General Expenses			1,000				1,003	3,471
77			Sub-total A&G Operations			$1,000				$10,117	$171,525
78											
79		A&G Maintenance	935.0 Maintenance of General Plant							$65	$7,828
80											
81			Sub-total ADMINISTRATION & GENERAL			$1,000				$10,182	$179,353
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$16,989	$16,989	$251,710
84			404.0 Amort. Of Limited-Term Electric Plant.						12,462	12,462	59,891
85			Sub-total Depreciation & Amortization Expense						$29,452	$29,452	$311,601
86											
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.							($448)	$10,749
88			Sub-total Amortization of Regulatory Expense							($448)	$10,749
89											
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					($5,754)		($5,754)	$193,432
91			Sub-total Taxes Other Than Income Taxes - Other					($5,754)		($5,754)	$193,432
92											
93			**Total**	**$3,572**	**$15,346**	**$957**		**($5,754)**	**$29,452**	**($20,800)**	**$2,547,038**

Line No.	Category	Category	Description	Account	(1) FTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act - 129 Lost Revenue Due To Load Reduction	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E OPEN	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization	(9) Adjustments Sub-total	(10) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	440.0	$930,799	$1,305	($1,498)	($1,883)	($22,941)		$501		($24,517)	$906,282
2			Residential - House Heating	440.1	177,985	969	(184)	(394)	(5,815)		147		(5,276)	172,709
3			C & I Small	442.0	295,923	618		(1,138)	(31,587)		152		(31,956)	263,968
4			C & I Large	442.1	218,153			(791)	(34,500)		125		(35,166)	182,986
5			Railroads & Railways	446.0	8,345				(1,127)				(1,127)	7,218
6			Street Lighting	444.0	22,374				(488)				(488)	21,886
7			Intercompany	448.0										
8			Transmission - All Classes		202,352									202,352
9			Sub-total - Customer & Distribution Revenues		$1,855,931	$2,892	($1,682)	($4,207)	($96,458)		$925		($98,530)	$1,757,401
10														
11		**Electric Cost Revenue**	Residential	440.0	$726,764									$726,764
12			Residential - House Heating	440.1	188,794									188,794
13			C & I Small	442.0	160,260									160,260
14			C & I Large	442.1	52,012									52,012
15			Railroads & Railways	446.0										
16			Street Lighting	444.0	845									845
17			Intercompany	448.0										
18			Sub-total - Electric Cost Revenue		$1,128,674									$1,128,674
19														
20			**Total OPERATING REVENUE**		$2,984,605	$2,892	($1,682)	($4,207)	($96,458)		$925		($98,530)	$2,886,075
21														
22	*OTHER REVENUE*	**Other Electric Revenue**	Rent For Electric Property	454.0	$22,021									$22,021
23			Other Electric Revenues	456.0	9,270									9,270
24			Transmission of Electricity for Others	456.1										
25			Sub-total - Other electric Revenue		$31,291									$31,291
26														
27		**Other Operating Revenue**	Forfeited Discounts	450.0	$11,428									$11,428
28			Miscellaneous Service Revenues	451.0	3,684									3,684
29			Sub-total - Other Operating Revenue		$15,111									$15,111
30														
31			**Total OTHER REVENUE**		$46,402									$46,402
32														
33			**Total REVENUE**		**$3,031,007**	**$2,892**	**($1,682)**	**($4,207)**	**($96,458)**		**$925**		**($98,530)**	**$2,932,477**

Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales	(3) 442001: C&I Sales-Small	(4) 442002: C&I Sales-Large	(5) C & I Total
1	Total FTY Revenues		$1,768,739	$395,893	$488,957	$298,215	$787,172
2	Commodity Billings in Revenues		(837,940)	(217,907)	(193,033)	(80,063)	(273,096)
3	Weather Adjustment						
4	Total Reconcilable Surcharge in Revenues		(16,550)	(4,151)	(27,064)	(26,056)	(53,120)
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$914,249	$173,834	$268,859	$192,097	$460,956
6							
7	Average Monthly Customers in FTY		1,334,031	201,708	156,062	3,110	159,172
8							
9	Average Annual Margin Per Customer	L5 / L7	$0.685	$0.862	$1.723	$61.767	$2.896
10							
11	Number of Customers at end of FTY		1,335,935	202,832	156,421	3,110	159,531
12							
13	Increase in Customers during FTY	L11 - L7	1,904	1,124	359		359
14							
15	**Annualization of Revenue**	L9 * L13	**$1,305**	**$969**	**$618**		**$618**

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			(1)	(2)	(3)
Line No.	Description		Reference	440000: Residental Sales	440001: Residental Heating Sales
1	CAP Discount			($121,394)	($14,867)
2					
3					
4	**ANNUALIZATION TO YEAR END CUSTOMERS**				
5					
6	Annual CAP Customers			1,353,900	170,244
7	Average Monthly CAP Customers			112,825	14,187
8	Average Annual CAP Discount Per Customer		L1 / L7	($1.076)	($1.048)
9					
10	CAP Customers at End of FTY			114,381	14,383
11	Increase of CAP Customers		L10 - L7	1,556	196
12					
13	Gross Decrease / (Increase) in CAP Discount		L8 * L11	($1,674)	($205)
14	Write-Offs & Working Capital Factor			10.5%	10.5%
15	Reflect Impact in Write-Offs and Working Capital		- L13 * L14	$176	$22
16					
17	**Net Decrease / (Increase) in CAP Discount**		L13 + L15	**($1,498)**	**($184)**

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	(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	2024 Revenue Loss	2025 Revenue Loss	2026 Revenue Loss Over 2025	Recovery of Incremental Revenue Loss
1	**Revenue Impact in 2024 - Included in FTY Year Budget**					
2	Residential		($4,135)			
3	Residential Heaing		(865)			
4	Small C&I		(3,123)			
5	Large C&I		(1,716)			
6	Total	SUM L2 to L5	($9,839)			
7						
8	**Target Revenue Impact in 2025**					
9	Residential			($7,902)		
10	Residential Heaing			(1,652)		
11	Small C&I			(5,399)		
12	Large C&I			(3,299)		
13	Total	SUM L9 to L12		($18,252)		
14						
15	**Incremental Revenue Impact Over FTY Budget**					
16	Residential	L9 - L2			($3,767)	
17	Residential Heaing	L10 - L3			(788)	
18	Small C&I	L11 - L4			(2,276)	
19	Large C&I	L12 - L5			(1,583)	
20	Total	SUM L16 to L19			($8,413)	
21						
22	**Average Annual Incremental Revenue Not in FTY Budget**					
23	Residential	L16 / 2				($1,883)
24	Residential Heaing	L17 / 2				(394)
25	Small C&I	L18 / 2				(1,138)
26	Large C&I	L19 / 2				(791)
27	**Total**	SUM L23 to L26				**($4,207)**

Line No.	Account / Description	(1) Reference	(2) Total
1	440000: Residential Sales		($22,941)
2	440001: Residential Heating Sales		(5,815)
3	442001: C&I Sales-Small		(31,587)
4	442002: C&I Sales-Large		(34,500)
5	444000: Public Street/Highway Lighting		(488)
6	446000: Sales-Railroad/Railway		(1,127)
7	**Reduction in Retail Revenue**	SUM L1 to L6	**($96,458)**
8			
9	O&M Expense		($90,706)

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	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Reference	440000: Residental Sales	440001: Residental Heating Sales	442001: C&I Sales-Small	442002: C&I Sales-Large	C & I Total
1	Revenue in February of FTY		$56,119	$16,517	$17,041	$13,951	$30,992
2	Days in February of FTY		28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	$2,004	$590	$609	$498	
4	Average Days in February		28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	
6							
7	**Leap Year Adjustment**	L3 * L5	**$501**	**$147**	**$152**	**$125**	**$277**

(1)

Line No.	Account	Total
1	Residental Sales	
2	Residental Heating Sales	
3	C&I Sales-Small	
4	C&I Sales-Large	
5		
6	**Total**	

Line No.	Description	Reference	(1) Union	(2) Non-Union
1	Number of Employees @ HTY - Union/Non-Union		1,044	1,168
2	Number of Employees @ HTY - Total		2,213	2,213
3	Percentage of Employees @ HTY	L1 / L2	47.20%	52.80%
4	Distribution of Budget S&W Expense		$75,632	$84,592
5				
6	**Annualize March 1 Wage Increase for FTY**			
7	Number of Months TY			2
8	Rate for Increase TY		2.50%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$423
10		L4 + L9	$75,632	$85,015
11				
12	**Annualize January 1 and March 1, 2025 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		2.50%	3.00%
15	Total Adjustment	(L10 * L13 * L14) / 12	$1,891	$2,550
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$77,523**	**$87,565**

		(1)	(2)
Line No.	Description	Reference	Amount
1	Distribution of S&W Expense		$160,224
2			
3	Annualized S&W Including Wage Increases		$165,088
4			
5	**Adjustment for Union Contract**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		77.49%
8	Union Contract Payment for Utility	L6 * L7	$1,010
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$168
11			
12	Adjusted S&W for Employees in FTY	L3 + L10	$165,256
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ FTY		2,340
16	Average Number of Employees in FTY - Total		2,298
17	Annualization for Number of Employees	L15 - L16	42
18	Annual S&W per Employee	L12 / L16	$71.9
19	Annualization of S&W for New Employees	L17 * L18	$3,038
20			
21	Pro Forma FTY S&W	L12 + L19	$168,294
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$8,070**
24			
25	S&W Pro Forma Factor	L23 / L1	5.04%

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
1	**Operations**	**Power Supply Expenses**	555.0 Purchased Power.			
2			Sub-total Power Supply Expenses			
3						
4		**Transmission Expense**	560.0 Operation & Supervision			
5			561.0 Load Dispatching			
6			561.4 Scheduling, System Control & Dispatch			
7			561.6 Transmission Service Studies			
8			561.7 Generation Service Studies			
9			561.8 Reliability, Planning & Standard Development			
10			562.0 Station Expense			
11			563.0 Overhead Lines			
12			564.0 Underground Lines Expense			
13			566.0 Miscellaneous Expense			
14			567.0 Rents			
15			569.0 Maintenance of Structures			
16			569.1 Maintenance of Computer Hardware			
17			569.2 Maintenance of Computer Software			
18			569.3 Maintenance of Communication Equipment			
19			570.0 Maintenance of Station Equipment			
20			571.0 Maintenance of Overhead Lines			
21			572.0 Maintenance of Underground Lines			
22			573.0 Maintenance of Misc Transmission Plant			
23			Sub-total Transmission Expense			
24						
25		**Distribution Expense**	580.0 Operation & Supervision	$985	$50	$1,034
26			581.0 Load Dispatching			
27			582.0 Station Expense	50	3	53
28			583.0 Overhead Lines Expenses	2,955	149	3,103
29			584.0 Underground Lines Expense	2,434	123	2,557
30			586.0 Meter Expenses	2,530	127	2,657
31			587.0 Customer Installations Expense	6,129	309	6,437
32			588.0 Miscellaneous Expense	6,901	348	7,249
33			589.0 Rents			
34			591.0 Maintenance of Structures	1,284	65	1,349
35			592.0 Maintenance of Station Equipment	8,456	426	8,882
36			593.0 Maintenance of Overhead Lines	41,472	2,089	43,561
37			594.0 Maintenance of Underground Lines	16,185	815	17,001
38			595.0 Maintenance of Line Transformers	474	24	498
39			596.0 Maintenance of Street Lighting & Signal Systems	99	5	104
40			598.0 Maintenance of Misc. Distribution	4,027	203	4,230
41			Sub-total Distribution Operations	$93,980	$4,734	$98,714
42						

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
43	**Customer Accounts**		901.0 Supervision			
44			902.0 Meter Reading	0	$0	0
45			903.0 Customer Records and Collection	$35,450	$1,786	$37,236
46			904.0 Uncollectible Accounts.			
47			905.0 Miscellaneous Customer Accounts Expenses.	757	38	795
48			Sub-total Customer Accounts	$36,208	$1,824	$38,031
49						
50	**Customer Service & Information**		908.0 Customer Assistance	$1,638	$82	$1,720
51			909.0 Informational & Instructional			
52			910.0 Miscellaneous Customer & Informational	210	11	220
53			Sub-total Customer Service & Information	$1,847	$93	$1,940
54						
55	**Sales**		912.0 Demonstrating & Selling	$219	$11	$230
56			916.0 Miscellaneous Sales			
57			Sub-total Sales	$219	$11	$230
58						
59	**Administration & General**		920.0 Administrative and General Salaries	$24,843	$1,251	$26,095
60			921.0 Office Supplies and Expenses			
61			922.0 Administrative Expenses Transferred-Credit			
62			923.0 Outside Service Employed			
63			924.0 Property Insurance			
64			925.0 Injuries & Damages	1,747	88	1,835
65			926.0 Employee Pensions and Benefits	33	2	35
66			928.0 Regulatory Commission Expenses			
67			929.0 Duplicate Charges-Credit			
68			930.2 Miscellaneous General Expenses	60	3	64
69			935.0 Maintenance of General Plant	1,286	65	1,351
70			Sub-total Administration & General	$27,970	$1,409	$29,379
71						
72			**Total**	**$160,224**	**$8,070**	**$168,294**
73						
74			**Percent Increase**			5.04%

		(1)	(2)
Line No.	Description	Reference	Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$3
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		$6
4	Total Recorded Up To Period End of HTY	SUM L2 to L3	$9
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$1,997
8	Materials, IT Costs, Travel, Copies, etc.		394
9	Total Expenditure Expected in FTY	SUM L7 to L8	$2,391
10			
11	Total Rate Case Expense	L4 + L9	$2,400
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,200
15			
16	Annual Amortization Amount Included in Budget		
17	**Pro Forma Adjustment for Annual Amortization**	L14 - L16	**$1,200**

Line No.	Description	Reference	(1) Jurisdictional Amount
1	**Number of Employees**		
2	Employees at Eleven Months Prior		2,246
3	Employees at Ten Months Prior		2,250
4	Employees at Nine Months Prior		2,245
5	Employees at Eight Months Prior		2,277
6	Employees at Seven Months Prior		2,283
7	Employees at Six Months Prior		2,285
8	Employees at Five Months Prior		2,305
9	Employees at Four Months Prior		2,312
10	Employees at Three Months Prior		2,340
11	Employees at Two Months Prior		2,340
12	Employees at One Month Prior		2,347
13	Employees at End of FTY		2,340
14			
15	Average Monthly Employees in FTY	AVERAGE L2 to L13	2,298
16	Additional Employees in FTY		42
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$22,496
20	Number of Employees for Budget		2,298
21	Budget Expense Per Employee	L19 / L20	$10
22	Additional Employees for Annualization	L16	42
23	**Total Benefits Pro Forma Adjustment**	L21 * L22	**$414**

Line No.	Description	Reference	Total - PECO
		(1)	(2)
1	Pension Contribution for Four Years Prior to FTY		$18,006
2	Pension Contribution for Three Years Prior to FTY		17,267
3	Pension Contribution for Two Years Prior to FTY		15,222
4	Pension Contribution for One Year Prior to FTY		1,408
5	Pension Contribution for FTY		2,878
6			
7	Average Pension Contribution	Average L1 to L5	$10,956
8			
9	Percent to Electric Distribution		77.49%
10	Total Amount to Electric Distribution	L7 * L9	$8,490
11	Pension Capitalization Factor		48.21%
12	Pension Contribution To Be Capitalized	L10 * L11	4,093
13	Pension Contribution To Be Expensed	L10 - L12	$4,396
14	FPFTY Distribution Pension Expense		(1,763)
15	**Additional Pension Expense**	L13 - L14	**$6,160**

Line No.	Description	Reference	Reference	Charge Off Amounts	InPA Charge Off Amounts	Net Charge Off Amounts	Billed Revenue	Percent	PPA	Totals
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$29,237	$2,395	$26,842	$3,365,014	0.7977%		
2		One Year Prior to HTY		37,820	(28)	37,848	3,810,090	0.9934%		
3		HTY		42,650	17	42,632	3,880,008	1.0988%		
4		Three Year Average	SUM L1 to L3 / 3	$36,569	$795	$35,774	$3,685,037	0.9708%		
5										
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	FTY					$2,886,075			
7										
8	Tariff Revenue - Non Shopping Revenue	FTY	L6				$2,886,075			
9										
10	Tariff Revenue - Shopping Revenue	FTY					1,107,648			
11										
12	Tariff Revenue - Including Shopping Revenue	FTY	L8 + L10				$3,993,723			
13										
14	**Total General Pro Forma Uncollectible Accounts**		Col 7 L4 * L12							$38,771
15										
16	**NET PPA UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY						$6,462		
17		One Year Prior to HTY						9,314		
18		HTY						12,116		
19										
20	**Three Year Average PPA**		SUM L16 to L18 / 3							$9,297
21										
22	**Total Pro Forma Uncollectible Accounts**		L14 + L20							$48,068
23										
24	Uncollectible Accounts (904)	FTY								$37,131
25										
26	**Total Pro Forma Adjustment for Uncollectible Accounts**		L22 - L24							**$10,937**

		(1)	(2)
Line No.	Description	Reference	Total
1	Actual IIJA Related Incremental Costs in 2022 and 2023		$411
2	Amortization Years		2
3	Pro Forma Adjustment Amount	L1 / L2	$205
4	Remove Estimated IIJA Related Incremental Costs in 2025		(653)
5	**Total Pro Forma Adjustment Amount**	L3 + L4	**($448)**

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Line No.	Description	Description	Reference	Interest Rate	Deposit Amount	Interest on Deposit Amount	Interest Sub Total	Interest Total
			(1)	(2)	(3)	(4)	(5)	(6)
1	**Residential**	Monthly Interest Rate		0.667%				
2								
3	January				18,976	127		
4	February				19,166	128		
5	March				19,446	130		
6	April				20,077	134		
7	May				20,877	139		
8	June				21,538	144		
9	July				22,060	147		
10	August				22,549	150		
11	September				22,772	152		
12	October				23,058	154		
13	November				23,276	155		
14	December				23,215	155		
15	**Total Residential**		SUM Col 4 L3 to L14				$1,713	
16								
17	**Non-Residential**	Monthly Interest Rate		0.425%				
18								
19	January				32,487	138		
20	February				33,197	141		
21	March				33,844	144		
22	April				34,307	146		
23	May				35,117	149		
24	June				35,642	151		
25	July				36,988	157		
26	August				38,022	162		
27	September				38,782	165		
28	October				39,358	167		
29	November				39,646	168		
30	December				39,988	170		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$1,859	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					**$3,572**

		(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Reference	Tri- State CPI Factor	Inflation Factor	Expense In Year	Amount for Average	Total
1	4/1/2019 - 3/31/2020		-	1.22448	$32,500	$39,796	
2	4/1/2020 - 3/31/2021		0.00696	1.22448	$118,822	$145,495	
3	4/1/2021 - 3/31/2022		0.05645	1.21602	$56,495	$68,699	
4	4/1/2022 - 3/31/2023		0.07555	1.15105	$17,144	$19,734	
5	4/1/2023 - 3/31/2024		0.03888	1.07019	$67,284	$72,006	
6	2024		0.01671	1.03014			
7							
8	Average Storm Restoration Expense at 2025 cost levels	AVERAGE L1 to L5					$69,146
9							
10	FTY Budget						$53,800
11							
12	**Pro Forma Adjustment for Storm Expense Normalization**	L9 - L11					**$15,346**

		(1)	(2)
Line No.	Description	Reference	Total
1	Final Tax Accounting Repair Credit (TARC) - Electric		
2	Residential		(36)
3	Small C&I		(14)
4	Large C&I		(9)
5	Street Lighting		(3)
6	Sub-total TARC Credit	SUM L2 to L5	($62)
7	Final Federal Tax Adjustment Credit (FTAC) - Electric		
8	Residential		($37)
9	Small C&I		(1)
10	Street Lighting		(0)
11	Large C&I & Railroads		15
12	Sub-total FTAC Credit	SUM L8 to L11	($23)
13	Total TARC and FTAC Credit	L6 + L12	($86)
14	Amortization Years		2
15	Pro Forma Adjustment Amount	L13 / L14	($43)
16			
17	EV Incentive Rebates		$1,000

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Line No.	Description	Transmission Percentage / Reference	(1) Total Electric	(2) Transmission Elimination	(3) Distribution	(4) Pro Forma Adjustments	(5) Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	17.825%	$6,924	($1,234)	$5,690		$5,690
2	Use Tax Accrued	17.825%	2,443	(435)	2,007		2,007
3	Real Estate Tax Accrued	17.825%	5,842	(1,041)	4,800		4,800
4	Miscellaneous TOTI	12.373%					
5	Payroll Tax Accrued	12.373%	13,927	(1,723)	12,204	615	12,819
6	Sub-total TOTI - Other	SUM L1 to L5	$29,135	($4,434)	$24,701	$615	$25,316
7							
8	Gross Receipt Tax		$174,486		$174,486	($6,369)	$168,117
9							
10	**Total**	L6 + L8	**$203,621**	**($4,434)**	**$199,187**	**($5,754)**	**$193,432**

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Line No.	Description	(1) Reference	(2) Jurisdictional
1	Total Payroll Charged to Expense		$160,224
2	Payroll Tax Expense		$12,204
3	Payroll Tax Expense - Percent	L2 / L1	7.62%
4	Pro Forma Increase in S&W		$8,070
5	**Payroll Tax Pro Forma**	L3 * L4	**$615**

Line No.	Description	Reference	(1) Total
1	**GROSS RECEIPTS TAX PRO FORMA AT PRESENT RATE**		(2)
2			
3	Residential		$1,633,045
4	Residential Heating		361,503
5	Small C&I		424,227
6	Large C&I		234,998
7	Railroads & Railways		7,218
8	Street Lighting & Highway		22,731
9	Interdepartmental Sales - Electric		
10	Transmission		202,352
11	Sub-total	SUM L3 to L10	$2,886,075
12			
13	Forfeited Discounts - Electric		$11,428
14	Uncollectible Accounts		(48,068)
15	COVID-19 Related Incremental Bad Debt Expense		
16	Sub-total	SUM L13 to L15	($36,640)
17			
18	Total FTY at Present Rates	L11 + L16	$2,849,435
19			
20	Gross Receipts Tax Rate		5.90%
21			
22	Pro Forma Gross Receipts Expense at Present Rates	L18 * L20	$168,117
23			
24	FTY Budget		$174,486
25			
26	**Net Adjustment**	L22 - L24	**($6,369)**

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Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	$1,894	$398	$1,496	$398	$2,291
2			PECO Elec 3650 PA LTIIP	3,041	490	2,551	490	3,530
3			PECO Elec 3660 PA LTIIP	2,977	805	2,172	805	3,782
4			PECO Elec 3670 PA LTIIP	4,353	850	3,503	850	5,204
5			PECO Elec 3705 SM UD RES PA	9,577		9,577		9,577
6			PECO Elec 3706 Non DOE Rcv PA	2,210		2,210		2,210
7			PECO Elec 3707 SM RES PA	5,546	107	5,439	107	5,654
8			PECO Elec 3708 SM SCI PA	825	3	822	3	829
9			PECO Elec 3709 SM LCI PA	1,161	22	1,139	22	1,184
10			PECO Elec Dist-ARC EXP PA	(42)		(42)		(42)
11			PECO Electric 3611 PA	1,639	159	1,479	159	1,798
12			PECO Electric 3612 PA	2,655	161	2,494	161	2,816
13			PECO Electric 3613 PA	197	0	197	0	198
14			PECO Electric 3620 PA	22,932	1,120	21,812	1,120	24,052
15			PECO Electric 3640 PA	25,288	2,194	23,094	2,194	27,481
16			PECO Electric 3650 PA	40,141	2,733	37,408	2,733	42,874
17			PECO Electric 3660 PA	9,666	1,046	8,620	1,046	10,712
18			PECO Electric 3670 PA	35,887	2,711	33,175	2,711	38,598
19			PECO Electric 3680 PA	18,403	1,214	17,190	1,214	19,617
20			PECO Electric 3691 PA	3,659	172	3,487	172	3,830
21			PECO Electric 3692 PA	4,959	70	4,889	70	5,029
22			PECO Electric 3701 PA	160	14	146	14	174
23			PECO Electric 3710 PA	4		4		4
24			PECO Electric 3730 PA	770	24	746	24	795
25			PECO Electric 3731 PA	73	0	73	0	73
26			PECO Electric 3732 PA	968	51	917	51	1,019
27			PECO Electric 3733 PA	34		34		34
28			Sub-total Electric - Distribution	$198,979	$14,344	$184,635	$14,344	$213,323
29			Sub-total Electric - Distribution	$198,979	$14,344	$184,635	$14,344	$213,323
30								
31		Common - General Plant	PECO Common 3901 PA	$4,118	$127	$3,990	$127	$4,245
32			PECO Common 3902 IL	16		16		16
33			PECO Common 3902 PA	3,818	1,031	2,787	1,031	4,849
34			PECO Common 3903 PA	91	28	63	28	119
35			PECO Common 3911 PA	13		13		13
36			PECO Common 3912 PA	2,256	81	2,175	81	2,337
37			PECO Common 3913 IL	1,039	144	895	144	1,184
38			PECO Common 3913 PA	8,106	1,341	6,764	1,341	9,447
39			PECO Common 3930 PA	98	2	96	2	100
40			PECO Common 3941 PA	1		1		1
41			PECO Common 3942 PA	66		66		66
42			PECO Common 3970 PA	6,577	494	6,083	494	7,071

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
43			PECO Common 3980 PA	84		84		84
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	12		12		12
45			PECO Elec 3919 SM Comp Equip IL	24		24		24
46			PECO Elec 3919 SM Comp Equip MD	8		8		8
47			PECO Elec 3919 SM Comp Equip NC	5		5		5
48			PECO Elec 3919 SM Comp Equip PA	7		7		7
49			PECO Elec 3949 SM Tools PA	6		6		6
50			PECO Elec 3979 SM Comm Equip PA	2,560	24	2,535	24	2,584
51			PECO Electric 3901 PA	794	5	789	5	800
52			PECO Electric 3902 PA	395	3	392	3	399
53			PECO Electric 3903 PA	8		8		8
54			PECO Electric 3911 PA	0		0		0
55			PECO Electric 3912 PA	67	2	64	2	69
56			PECO Electric 3913 PA	5,192	139	5,053	139	5,331
57			PECO Electric 3930 PA	4		4		4
58			PECO Electric 3940 PA	3,603	145	3,458	145	3,748
59			PECO Electric 3951 PA	11		11		11
60			PECO Electric 3952 PA	1		1		1
61			PECO Electric 3970 PA	7,753	193	7,560	193	7,946
62			PECO Electric 3980 PA	72	6	66	6	78
63			Sub-total Electric - General Plant	$46,804	$3,768	$43,036	$3,768	$50,573
64			Sub-total Electric - General Plant	$46,804	$3,768	$43,036	$3,768	$50,573
65								
66		Electric - Transmission	PECO Electric 3521 PA	$397	$1	$396	$1	$398
67			PECO Electric 3522 MD	1		1		1
68			PECO Electric 3522 NJ	0		0		0
69			PECO Electric 3522 PA	1,593	93	1,501	93	1,686
70			PECO Electric 3523 NJ	0		0		0
71			PECO Electric 3523 PA	49		49		49
72			PECO Electric 3530 NJ	65		65		65
73			PECO Electric 3530 PA	18,458	780	17,678	780	19,238
74			PECO Electric 3540 DE	91		91		91
75			PECO Electric 3540 MD	52		52		52
76			PECO Electric 3540 NJ	216		216		216
77			PECO Electric 3540 PA	3,114	26	3,087	26	3,140
78			PECO Electric 3550 PA	522	55	468	55	577
79			PECO Electric 3560 DE	5		5		5
80			PECO Electric 3560 MD	12		12		12
81			PECO Electric 3560 NJ	139	10	129	10	150
82			PECO Electric 3560 PA	4,818	627	4,191	627	5,445
83			PECO Electric 3570 PA	864	216	648	216	1,080
84			PECO Electric 3580 PA	2,206	183	2,023	183	2,389

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
85			PECO Electric 3590 NJ	4		4		4
86			PECO Electric 3590 PA	26	2	25	2	28
87			Sub-total Electric - Transmission	$32,633	$1,992	$30,641	$1,992	$34,626
88								
89			Sub-total 403.0 Depreciation Expense	$278,416	$20,105	$258,312	$20,105	$298,521
90			Sub-total Electric - Transmission	$32,633	$1,992	$30,641	$1,992	$34,626
91								
92	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	$10,909	$10,909		$10,909	$21,819
93			PECO - BIDA - Smart Energy Services	43	43		43	85
94			PECO - Distribution - ADMS	2,211	2,211		2,211	4,421
95			PECO - Distribution - IT	427	427		427	853
96			PECO - Transmission - IT	136	136		136	273
97			PECO Com 3030- North Star RE SW	391		391		391
98			PECO Com 3030-Apollo SW	967		967		967
99			PECO Com 3030-BIDA Customer Project	849		849		849
100			PECO Com 3030-BIDA-AMI Ph2 SW	2,139		2,139		2,139
101			PECO Com 3030-CIS Transformation SW	204		204		204
102			PECO Com 3030-Cloud Serv 3 yr	4,143	2,109	2,034	2,109	6,252
103			PECO Com 3030-Cloud Serv 5 yr	3,358		3,358		3,358
104			PECO Com 3030-Common MDM SW	2,040		2,040		2,040
105			PECO Com 3030-Cust Appt Sched SW	436		436		436
106			PECO Com 3030-EU Dig Strat EPay SW	164		164		164
107			PECO Com 3030-EU Digital Program We	2,002		2,002		2,002
108			PECO Com 3030-EU oneMDS SW	5,269		5,269		5,269
109			PECO Com 3030-Fusion Mig Non-MDM SW	33		33		33
110			PECO Com 3030-I Sign Up and Move	466		466		466
111			PECO Com 3030-IT Cust Mobile App SW	112		112		112
112			PECO Com 3030-IVR System PA	159		159		159
113			PECO Com 3030-Lease IT SW	14		14		14
114			PECO Com 3030-Misc 5 yr FR PA	6,164	652	5,512	652	6,816
115			PECO Com 3030-Misc 5 yr PA	60		60		60
116			PECO Com 3030-Mobile Dispatch Mappi	5,842		5,842		5,842
117			PECO Com 3030-OBIEE Migration SW	801		801		801
118			PECO Com 3030-PECO RNI Upgrade SW	(0)		(0)		(0)
119			PECO Com 3030-Robotic Process Auto	63		63		63
120			PECO Elec 303 EV-FC	32		32		32
121			PECO Elec 303 SLC	51		51		51
122			PECO Elec 303 SM AMOS PA	379		379		379
123			PECO Elec 303-BIDA Grid T&D Domain	1,797		1,797		1,797
124			PECO Elec 303-CFP - Outage SW D	566		566		566
125			PECO Elec 303-Dist Auto Ntwk Upg Hi	477		477		477
126			PECO Elec 303-EMS Implementation Pr	3,321		3,321		3,321

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
127			PECO Elec 303-EU Custom Analytics S	278		278		278
128			PECO Elec 303-EU Digital Solar Tool	177		177		177
129			PECO Elec 303-EU Load Forecast SW	723		723		723
130			PECO Elec 303-EU Ratings DB SW D	12		12		12
131			PECO Elec 303-EU Ratings DB SW T	155		155		155
132			PECO Elec 303-EU TOA Implementation	893		893		893
133			PECO Elec 303-PECO RNI Upgrade SW D	1,380		1,380		1,380
134			PECO Elec 303-SES IV D SW	2,364		2,364		2,364
135			PECO Elec 3030 - BIDA Smart Energy A (Original)	38		38		38
136			PECO Elec 3030-Cloud Serv 3 yr	254		254		254
137			PECO Elec 3030-Cloud Serv 5 yr	759		759		759
138			PECO Electric 303 Misc 5 FR PA	4,382		4,382		4,382
139			Sub-total Electric - Intangible Plant	$67,439	$16,487	$50,952	$16,487	$83,925
140								
141			Sub-total 404.0 Amort. of Limited-Term Electric Plant	$67,439	$16,487	$50,952	$16,487	$83,925
142								
143			**Total**	$345,855	$36,592	$309,263	$36,592	$382,446
144			Sub-total Electric - Intangible Plant	$67,439	$16,487	$50,952	$16,487	$83,925
145								
146			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.	$67,439	$16,487	$50,952	$16,487	$83,925

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$1,894	$398	$1,496	$398	$2,291
2			PECO Elec 3650 PA LTIIP	1.0000	3,041	490	2,551	490	3,530
3			PECO Elec 3660 PA LTIIP	1.0000	2,977	805	2,172	805	3,782
4			PECO Elec 3670 PA LTIIP	1.0000	4,353	850	3,503	850	5,204
5			PECO Elec 3705 SM UD RES PA	1.0000	9,577		9,577		9,577
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	2,210		2,210		2,210
7			PECO Elec 3707 SM RES PA	1.0000	5,546	107	5,439	107	5,654
8			PECO Elec 3708 SM SCI PA	1.0000	825	3	822	3	829
9			PECO Elec 3709 SM LCI PA	1.0000	1,161	22	1,139	22	1,184
10			PECO Elec Dist-ARC EXP PA	1.0000	(42)		(42)		(42)
11			PECO Electric 3611 PA	1.0000	1,639	159	1,479	159	1,798
12			PECO Electric 3612 PA	1.0000	2,655	161	2,494	161	2,816
13			PECO Electric 3613 PA	1.0000	197	0	197	0	198
14			PECO Electric 3620 PA	1.0000	22,932	1,120	21,812	1,120	24,052
15			PECO Electric 3640 PA	1.0000	25,288	2,194	23,094	2,194	27,481
16			PECO Electric 3650 PA	1.0000	40,141	2,733	37,408	2,733	42,874
17			PECO Electric 3660 PA	1.0000	9,666	1,046	8,620	1,046	10,712
18			PECO Electric 3670 PA	1.0000	35,887	2,711	33,175	2,711	38,598
19			PECO Electric 3680 PA	1.0000	18,403	1,214	17,190	1,214	19,617
20			PECO Electric 3691 PA	1.0000	3,659	172	3,487	172	3,830
21			PECO Electric 3692 PA	1.0000	4,959	70	4,889	70	5,029
22			PECO Electric 3701 PA	1.0000	160	14	146	14	174
23			PECO Electric 3710 PA	1.0000	4		4		4
24			PECO Electric 3730 PA	1.0000	770	24	746	24	795
25			PECO Electric 3731 PA	1.0000	73	0	73	0	73
26			PECO Electric 3732 PA	1.0000	968	51	917	51	1,019
27			PECO Electric 3733 PA	1.0000	34		34		34
28			Sub-total Electric - Distribution		$198,979	$14,344	$184,635	$14,344	$213,323
29			Sub-total Electric - Distribution		$198,979	$14,344	$184,635	$14,344	$213,323
30									
31		Common - General Plant	PECO Common 3901 PA	0.7693	$3,168	$98	$3,070	$98	$3,265
32			PECO Common 3902 IL	0.7693	12		12		12
33			PECO Common 3902 PA	0.7693	2,937	793	2,144	793	3,730
34			PECO Common 3903 PA	0.7693	70	22	48	22	92
35			PECO Common 3911 PA	0.7693	10		10		10
36			PECO Common 3912 PA	0.7693	1,735	62	1,673	62	1,798
37			PECO Common 3913 IL	0.7693	800	111	688	111	911
38			PECO Common 3913 PA	0.7693	6,236	1,032	5,204	1,032	7,268
39			PECO Common 3930 PA	0.7693	75	2	74	2	77
40			PECO Common 3941 PA	0.7693	1		1		1
41			PECO Common 3942 PA	0.7693	51		51		51
42			PECO Common 3970 PA	0.7693	5,060	380	4,680	380	5,440

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
43			PECO Common 3980 PA	0.7693	65		65		65
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	1.0000	12		12		12
45			PECO Elec 3919 SM Comp Equip IL	1.0000	24		24		24
46			PECO Elec 3919 SM Comp Equip MD	1.0000	8		8		8
47			PECO Elec 3919 SM Comp Equip NC	1.0000	5		5		5
48			PECO Elec 3919 SM Comp Equip PA	1.0000	7		7		7
49			PECO Elec 3949 SM Tools PA	1.0000	6		6		6
50			PECO Elec 3979 SM Comm Equip PA	1.0000	2,560	24	2,535	24	2,584
51			PECO Electric 3901 PA	1.0000	794	5	789	5	800
52			PECO Electric 3902 PA	1.0000	395	3	392	3	399
53			PECO Electric 3903 PA	1.0000	8		8		8
54			PECO Electric 3911 PA	1.0000	0		0		0
55			PECO Electric 3912 PA	1.0000	67	2	64	2	69
56			PECO Electric 3913 PA	1.0000	5,192	139	5,053	139	5,331
57			PECO Electric 3930 PA	1.0000	4		4		4
58			PECO Electric 3940 PA	1.0000	3,603	145	3,458	145	3,748
59			PECO Electric 3951 PA	1.0000	11		11		11
60			PECO Electric 3952 PA	1.0000	1		1		1
61			PECO Electric 3970 PA	1.0000	7,753	193	7,560	193	7,946
62			PECO Electric 3980 PA	1.0000	72	6	66	6	78
63			Sub-total Electric - General Plant		$40,741	$3,019	$37,722	$3,019	$43,760
64			Sub-total Electric - General Plant		$40,741	$3,019	$37,722	$3,019	$43,760
65									
66		Electric - Transmission	PECO Electric 3521 PA	1.0000	$397	$1	$396	$1	$398
67			PECO Electric 3522 MD	1.0000	1		1		1
68			PECO Electric 3522 NJ	1.0000	0		0		0
69			PECO Electric 3522 PA	1.0000	1,593	93	1,501	93	1,686
70			PECO Electric 3523 NJ	1.0000	0		0		0
71			PECO Electric 3523 PA	1.0000	49		49		49
72			PECO Electric 3530 NJ	1.0000	65		65		65
73			PECO Electric 3530 PA	1.0000	18,458	780	17,678	780	19,238
74			PECO Electric 3540 DE	1.0000	91		91		91
75			PECO Electric 3540 MD	1.0000	52		52		52
76			PECO Electric 3540 NJ	1.0000	216		216		216
77			PECO Electric 3540 PA	1.0000	3,114	26	3,087	26	3,140
78			PECO Electric 3550 PA	1.0000	522	55	468	55	577
79			PECO Electric 3560 DE	1.0000	5		5		5
80			PECO Electric 3560 MD	1.0000	12		12		12
81			PECO Electric 3560 NJ	1.0000	139	10	129	10	150
82			PECO Electric 3560 PA	1.0000	4,818	627	4,191	627	5,445
83			PECO Electric 3570 PA	1.0000	864	216	648	216	1,080
84			PECO Electric 3580 PA	1.0000	2,206	183	2,023	183	2,389

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
85			PECO Electric 3590 NJ	1.0000	4		4		4
86			PECO Electric 3590 PA	1.0000	26	2	25	2	28
87			Sub-total Electric - Transmission		$32,633	$1,992	$30,641	$1,992	$34,626
88									
89			Sub-total 403.0 Depreciation Expense		$272,353	$19,355	$252,998	$19,355	$291,708
90			Sub-total Electric - Transmission		$32,633	$1,992	$30,641	$1,992	$34,626
91									
92	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	0.7450	$8,128	$8,128		$8,128	$16,256
93			PECO - BIDA - Smart Energy Services	1.0000	43	43		43	85
94			PECO - Distribution - ADMS	1.0000	2,211	2,211		2,211	4,421
95			PECO - Distribution - IT	1.0000	427	427		427	853
96			PECO - Transmission - IT	1.0000	136	136		136	273
97			PECO Com 3030- North Star RE SW	0.7693	301		301		301
98			PECO Com 3030-Apollo SW	0.7693	744		744		744
99			PECO Com 3030-BIDA Customer Project	0.7693	653		653		653
100			PECO Com 3030-BIDA-AMI Ph2 SW	0.7693	1,645		1,645		1,645
101			PECO Com 3030-CIS Transformation SW	0.7693	157		157		157
102			PECO Com 3030-Cloud Serv 3 yr	0.7693	3,187	1,623	1,564	1,623	4,809
103			PECO Com 3030-Cloud Serv 5 yr	0.7693	2,584		2,584		2,584
104			PECO Com 3030-Common MDM SW	0.7693	1,570		1,570		1,570
105			PECO Com 3030-Cust Appt Sched SW	0.7693	335		335		335
106			PECO Com 3030-EU Dig Strat EPay SW	0.7693	126		126		126
107			PECO Com 3030-EU Digital Program We	0.7693	1,540		1,540		1,540
108			PECO Com 3030-EU oneMDS SW	0.7693	4,053		4,053		4,053
109			PECO Com 3030-Fusion Mig Non-MDM SW	0.7693	25		25		25
110			PECO Com 3030-I Sign Up and Move	0.7693	359		359		359
111			PECO Com 3030-IT Cust Mobile App SW	0.7693	86		86		86
112			PECO Com 3030-IVR System PA	0.7693	122		122		122
113			PECO Com 3030-Lease IT SW	0.7693	11		11		11
114			PECO Com 3030-Misc 5 yr FR PA	0.7693	4,742	502	4,241	502	5,244
115			PECO Com 3030-Misc 5 yr PA	0.7693	46		46		46
116			PECO Com 3030-Mobile Dispatch Mappi	0.7693	4,494		4,494		4,494
117			PECO Com 3030-OBIEE Migration SW	0.7693	616		616		616
118			PECO Com 3030-PECO RNI Upgrade SW	0.7693	(0)		(0)		(0)
119			PECO Com 3030-Robotic Process Auto	0.7693	49		49		49
120			PECO Elec 303 EV-FC	1.0000	32		32		32
121			PECO Elec 303 SLC	1.0000	51		51		51
122			PECO Elec 303 SM AMOS PA	1.0000	379		379		379
123			PECO Elec 303-BIDA Grid T&D Domain	1.0000	1,797		1,797		1,797
124			PECO Elec 303-CFP - Outage SW D	1.0000	566		566		566
125			PECO Elec 303-Dist Auto Ntwk Upg Hi	1.0000	477		477		477
126			PECO Elec 303-EMS Implementation Pr	1.0000	3,321		3,321		3,321

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
127			PECO Elec 303-EU Custom Analytics S	1.0000	278		278		278
128			PECO Elec 303-EU Digital Solar Tool	1.0000	177		177		177
129			PECO Elec 303-EU Load Forecast SW	1.0000	723		723		723
130			PECO Elec 303-EU Ratings DB SW D	1.0000	12		12		12
131			PECO Elec 303-EU Ratings DB SW T	1.0000	155		155		155
132			PECO Elec 303-EU TOA Implementation	1.0000	893		893		893
133			PECO Elec 303-PECO RNI Upgrade SW D	1.0000	1,380		1,380		1,380
134			PECO Elec 303-SES IV D SW	1.0000	2,364		2,364		2,364
135			PECO Elec 3030 - BIDA Smart Energy A (Original)	1.0000	38		38		38
136			PECO Elec 3030-Cloud Serv 3 yr	1.0000	254		254		254
137			PECO Elec 3030-Cloud Serv 5 yr	1.0000	759		759		759
138			PECO Electric 303 Misc 5 FR PA	1.0000	4,382		4,382		4,382
139			Sub-total Electric - Intangible Plant		$56,427	$13,068	$43,358	$13,068	$69,495
140									
141			Sub-total 404.0 Amort. of Limited-Term Electric Plant		$56,427	$13,068	$43,358	$13,068	$69,495
142									
143			**Total**		$328,780	$32,423	$296,356	$32,423	$361,203
144			Sub-total Electric - Intangible Plant		$56,427	$13,068	$43,358	$13,068	$69,495
145									
146			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.		$56,427	$13,068	$43,358	$13,068	$69,495

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$1,894	$398	$1,496	$398	$2,291
2			PECO Elec 3650 PA LTIIP	1.0000	$3,041	490	2,551	490	3,530
3			PECO Elec 3660 PA LTIIP	1.0000	$2,977	805	2,172	805	3,782
4			PECO Elec 3670 PA LTIIP	1.0000	$4,353	850	3,503	850	5,204
5			PECO Elec 3705 SM UD RES PA	1.0000	$9,577		9,577		9,577
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	$2,210		2,210		2,210
7			PECO Elec 3707 SM RES PA	1.0000	$5,546	107	5,439	107	5,654
8			PECO Elec 3708 SM SCI PA	1.0000	$825	3	822	3	829
9			PECO Elec 3709 SM LCI PA	1.0000	$1,161	22	1,139	22	1,184
10			PECO Elec Dist-ARC EXP PA						
11			PECO Electric 3611 PA	1.0000	$1,639	159	1,479	159	1,798
12			PECO Electric 3612 PA	1.0000	$2,655	161	2,494	161	2,816
13			PECO Electric 3613 PA	1.0000	$197	0	197	0	198
14			PECO Electric 3620 PA	1.0000	$22,932	1,120	21,812	1,120	24,052
15			PECO Electric 3640 PA	1.0000	$25,288	2,194	23,094	2,194	27,481
16			PECO Electric 3650 PA	1.0000	$40,141	2,733	37,408	2,733	42,874
17			PECO Electric 3660 PA	1.0000	$9,666	1,046	8,620	1,046	10,712
18			PECO Electric 3670 PA	1.0000	$35,887	2,711	33,175	2,711	38,598
19			PECO Electric 3680 PA	1.0000	$18,403	1,214	17,190	1,214	19,617
20			PECO Electric 3691 PA	1.0000	$3,659	172	3,487	172	3,830
21			PECO Electric 3692 PA	1.0000	$4,959	70	4,889	70	5,029
22			PECO Electric 3701 PA	1.0000	$160	14	146	14	174
23			PECO Electric 3710 PA	1.0000	$4		4		4
24			PECO Electric 3730 PA	1.0000	$770	24	746	24	795
25			PECO Electric 3731 PA	1.0000	$73	0	73	0	73
26			PECO Electric 3732 PA	1.0000	$968	51	917	51	1,019
27			PECO Electric 3733 PA	1.0000	$34		34		34
28			Sub-total Electric - Distribution		$199,020	$14,344	$184,676	$14,344	$213,365
29			Sub-total Electric - Distribution		$199,020	$14,344	$184,676	$14,344	$213,365
30									
31		Common - General Plant	PECO Common 3901 PA	0.8763	$2,776	$86	$2,690	$86	$2,861
32			PECO Common 3902 IL	0.8763	11		11		11
33			PECO Common 3902 PA	0.8763	2,574	695	1,878	695	3,269
34			PECO Common 3903 PA	0.8763	61	19	42	19	80
35			PECO Common 3911 PA	0.8763	8		8		8
36			PECO Common 3912 PA	0.8763	1,521	54	1,466	54	1,575
37			PECO Common 3913 IL	0.8763	701	97	603	97	798
38			PECO Common 3913 PA	0.8763	5,464	904	4,560	904	6,368
39			PECO Common 3930 PA	0.8763	66	1	65	1	67
40			PECO Common 3941 PA	0.8763	1		1		1
41			PECO Common 3942 PA	0.8763	45		45		45
42			PECO Common 3970 PA	0.8763	4,434	333	4,101	333	4,767

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
43			PECO Common 3980 PA	0.8763	57		57		57
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	0.8763	11		11		11
45			PECO Elec 3919 SM Comp Equip IL	0.8763	21		21		21
46			PECO Elec 3919 SM Comp Equip MD	0.8763	7		7		7
47			PECO Elec 3919 SM Comp Equip NC	0.8763	4		4		4
48			PECO Elec 3919 SM Comp Equip PA	0.8763	7		7		7
49			PECO Elec 3949 SM Tools PA	0.8763	6		6		6
50			PECO Elec 3979 SM Comm Equip PA	0.8763	2,243	21	2,222	21	2,264
51			PECO Electric 3901 PA	0.8763	696	5	691	5	701
52			PECO Electric 3902 PA	0.8763	347	3	344	3	350
53			PECO Electric 3903 PA	0.8763	7		7		7
54			PECO Electric 3911 PA	0.8763	0		0		0
55			PECO Electric 3912 PA	0.8763	58	2	56	2	60
56			PECO Electric 3913 PA	0.8763	4,550	122	4,428	122	4,672
57			PECO Electric 3930 PA	0.8763	3		3		3
58			PECO Electric 3940 PA	0.8763	3,157	127	3,030	127	3,285
59			PECO Electric 3951 PA	0.8763	10		10		10
60			PECO Electric 3952 PA	0.8763	0		0		0
61			PECO Electric 3970 PA	0.8763	6,794	169	6,625	169	6,963
62			PECO Electric 3980 PA	0.8763	63	5	58	5	68
63			Sub-total Electric - General Plant		$35,700	$2,645	$33,055	$2,645	$38,345
64			Sub-total Electric - General Plant		$35,700	$2,645	$33,055	$2,645	$38,345
65									
66		Electric - Transmission	PECO Electric 3521 PA						
67			PECO Electric 3522 MD						
68			PECO Electric 3522 NJ						
69			PECO Electric 3522 PA						
70			PECO Electric 3523 NJ						
71			PECO Electric 3523 PA						
72			PECO Electric 3530 NJ						
73			PECO Electric 3530 PA						
74			PECO Electric 3540 DE						
75			PECO Electric 3540 MD						
76			PECO Electric 3540 NJ						
77			PECO Electric 3540 PA						
78			PECO Electric 3550 PA						
79			PECO Electric 3560 DE						
80			PECO Electric 3560 MD						
81			PECO Electric 3560 NJ						
82			PECO Electric 3560 PA						
83			PECO Electric 3570 PA						
84			PECO Electric 3580 PA						

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
85			PECO Electric 3590 NJ						
86			PECO Electric 3590 PA						
87			Sub-total Electric - Transmission						
88									
89			Sub-total 403.0 Depreciation Expense		$234,720	$16,989	$217,731	$16,989	$251,710
90			Sub-total Electric - Transmission						
91									
92	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	1.0000	$8,128	$8,128		$8,128	$16,256
93			PECO - BIDA - Smart Energy Services	1.0000	43	43		43	85
94			PECO - Distribution - ADMS	0.8763	1,937	1,937		1,937	3,874
95			PECO - Distribution - IT	0.8763	374	374		374	748
96			PECO - Transmission - IT	0.8763	120	120		120	239
97			PECO Com 3030- North Star RE SW	0.8763	264		264		264
98			PECO Com 3030-Apollo SW	0.8763	652		652		652
99			PECO Com 3030-BIDA Customer Project	0.8763	572		572		572
100			PECO Com 3030-BIDA-AMI Ph2 SW	0.8763	1,442		1,442		1,442
101			PECO Com 3030-CIS Transformation SW	0.8763	138		138		138
102			PECO Com 3030-Cloud Serv 3 yr	0.8763	2,793	1,422	1,371	1,422	4,214
103			PECO Com 3030-Cloud Serv 5 yr	0.8763	2,264		2,264		2,264
104			PECO Com 3030-Common MDM SW	0.8763	1,375		1,375		1,375
105			PECO Com 3030-Cust Appt Sched SW	0.8763	294		294		294
106			PECO Com 3030-EU Dig Strat EPay SW	0.8763	111		111		111
107			PECO Com 3030-EU Digital Program We	0.8763	1,349		1,349		1,349
108			PECO Com 3030-EU oneMDS SW	0.8763	3,552		3,552		3,552
109			PECO Com 3030-Fusion Mig Non-MDM SW	0.8763	22		22		22
110			PECO Com 3030-I Sign Up and Move	0.8763	314		314		314
111			PECO Com 3030-IT Cust Mobile App SW	0.8763	75		75		75
112			PECO Com 3030-IVR System PA	0.8763	107		107		107
113			PECO Com 3030-Lease IT SW	0.8763	9		9		9
114			PECO Com 3030-Misc 5 yr FR PA	0.8763	4,155	439	3,716	439	4,595
115			PECO Com 3030-Misc 5 yr PA	0.8763	40		40		40
116			PECO Com 3030-Mobile Dispatch Mappi	0.8763	3,938		3,938		3,938
117			PECO Com 3030-OBIEE Migration SW	0.8763	540		540		540
118			PECO Com 3030-PECO RNI Upgrade SW	0.8763	(0)		(0)		(0)
119			PECO Com 3030-Robotic Process Auto	0.8763	43		43		43
120			PECO Elec 303 EV-FC	1.0000	32		32		32
121			PECO Elec 303 SLC	1.0000	51		51		51
122			PECO Elec 303 SM AMOS PA	1.0000	379		379		379
123			PECO Elec 303-BIDA Grid T&D Domain	0.8763	1,574		1,574		1,574
124			PECO Elec 303-CFP - Outage SW D	1.0000	566		566		566
125			PECO Elec 303-Dist Auto Ntwk Upg Hi	1.0000	477		477		477
126			PECO Elec 303-EMS Implementation Pr						

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
127			PECO Elec 303-EU Custom Analytics S	1.0000	278		278		278
128			PECO Elec 303-EU Digital Solar Tool	1.0000	177		177		177
129			PECO Elec 303-EU Load Forecast SW	1.0000	723		723		723
130			PECO Elec 303-EU Ratings DB SW D	1.0000	12		12		12
131			PECO Elec 303-EU Ratings DB SW T						
132			PECO Elec 303-EU TOA Implementation						
133			PECO Elec 303-PECO RNI Upgrade SW D	1.0000	1,380		1,380		1,380
134			PECO Elec 303-SES IV D SW	1.0000	2,364		2,364		2,364
135			PECO Elec 3030 - BIDA Smart Energy A (Original)	1.0000	38		38		38
136			PECO Elec 3030-Cloud Serv 3 yr	0.8763	223		223		223
137			PECO Elec 3030-Cloud Serv 5 yr	0.8763	665		665		665
138			PECO Electric 303 Misc 5 FR PA	0.8763	3,839		3,839		3,839
139			Sub-total Electric - Intangible Plant		$47,429	$12,462	$34,967	$12,462	$59,891
140									
141			Sub-total 404.0 Amort. of Limited-Term Electric Plant		$47,429	$12,462	$34,967	$12,462	$59,891
142									
143			**Total**		$282,149	$29,452	$252,698	$29,452	$311,601
144			Sub-total Electric - Intangible Plant		$47,429	$12,462	$34,967	$12,462	$59,891
145									
146			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.		$47,429	$12,462	$34,967	$12,462	$59,891

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Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$2,932,477	$357,459	$3,289,936
2	Operating Expenses		2,547,038	25,346	2,572,384
3	OIBIT	L1 - L2	$385,439	$332,112	$717,551
4					
5	Rate Base		$7,948,351		$7,948,351
6	Weighted Cost of Debt		2.030%		2.030%
7	Synchronized Interest Expense	L5 * L6	$161,352		$161,352
8	Base Taxable Income	L3 - L7	$224,087	$332,112	$556,200
9					
10	State Accelerated Tax Depreciation		$349,847		$349,847
11	Pro Forma Book Depreciation		311,601		311,601
12	State Tax Depreciation (Over) Under Book	L11 - L10	($38,245)		($38,245)
13	Regulatory Asset Programs M-1, Pension and Post Retirement & Other		(2,156)		(2,156)
14	Other Property Basis Adjustments (CIAC/ICM)		(56,196)		(56,196)
15	Removal Costs/Software		(7,116)		(7,116)
16	AFUDC Equity		(24,787)		(24,787)
17	Permanent Adjustments		4,245		4,245
18	Repair Deduction		(181,800)		(181,800)
19					
20	State Taxable Income	L8 + SUM (L12 to L18)	($81,968)	$332,112	$250,145
21					
22	State Income Tax Rate		8.49%	8.49%	8.49%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L22 * L20)	$6,959	($28,196)	($21,237)
24	Net Operating Loss Utilization %		40.00%	40.00%	40.00%
25	Net Operating Loss Utilization	- L24 * L23	(2,784)	11,279	8,495
26	State Income Tax Benefit / (Expense)	L23 + L25	$4,175	($16,918)	($12,742)
27					
28	Federal Accelerated Tax Depreciation		$311,358		$311,358
29	Pro Forma Book Depreciation		311,601		311,601
30	Federal Tax Deducts (Over) Under Book	L29 - L28	$243		$243
31	Regulatory Asset Programs M-1		(2,156)		(2,156)
32	Other Property Basis Adjustments (CIAC/ICM)		(56,196)		(56,196)
33	Removal Costs/Software		(7,116)		(7,116)
34	AFUDC Equity		(24,787)		(24,787)
35	Permanent Adjustments		4,245		4,245
36	Repair Deduction		(181,800)		(181,800)
37	Federal NOL				
38	Federal Taxable Income	L8 + L26 + SUM (L30 to L37)	($39,303)	$315,195	$275,891
39					
40	Federal Income Tax Rate %		21.00%	21.00%	
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	-	$8,254	($66,191)	($57,937)
42	Corporate Alternative Minimum Tax		($48,211)		($48,211)
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	($35,782)	($83,109)	($118,890)
44					

Line No.	Description	Reference	Present Rates	Rate Increase	Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($13,241)	$2,368	(10,873)
47	Deferred Taxes on Timing Differences- State		(4,954)		(4,954)
48	Deferred Taxes on State NOL		2,784	(11,279)	(8,495)
49	Excess Deferred Amortization		6,987		6,987
50	Excess Deferred Amortization - State (Net of Federal)		232		232
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax Expense on Flow Through Adjustment		(3,454)		(3,454)
53	Corporate Alternative Minimum Tax		48,211		48,211
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	$36,564	($8,910)	$27,654
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	$783	($92,019)	($91,236)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		$15		$15
60					
61	Combined Income Tax Benefit / (Expense)	SUM L56 to L59	$797	($92,019)	($91,221)
62					
63	**Federal Income Tax Benefit / (Expense)**	L41 + L46 + L49 + L51 + L52 + L59	**($1,439)**	**($63,822)**	**($65,262)**
64	**State Income Tax Benefit / (Expense)**	L26 + L47 + L48 + L50	**$2,237**	**($28,196)**	**($25,960)**
65	**Total Income Tax Benefit / (Expense)**	L63 + L64	**$797**	**($92,019)**	**($91,221)**

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		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Reference	2018	2019	2020	2021	2022	Average
1	PECO Consolidated Taxable Income		$149,524	$191,310	($22,448)	$33,306	$135,993	
2								
3								
4	Consolidated Income Companies Taxable Income		$1,005,422	$931,575	$937,098	$1,705,766	$816,851	
5								
6								
7	Taxable Income Percentage to PECO	L1 / L4	14.87%	20.54%		1.95%	16.65%	
8								
9								
10	Consolidated Companies Loss		$ (85,736)	$ (162,524)	$ (249,053)	$ (575,746)	$ (108,853)	
11								
12								
13	PECO Allocation of Loss	L7 * L10	$ (12,750)	$ (33,376)	$ -	$ (11,242)	$ (18,122)	
14								
15								
16	Electric Percentage		106.61%	125.46%	-88.07%	376.30%	158.98%	
17								
18								
19	Loss Allocable to Electric	L13 * L16	($13,593)	($41,874)		($42,303)	($28,809)	
20								
21								
22								
23	Average for 2018 to 2022	Average L19						(25,316)
24								
25								
26	Tax Rate							21.00%
27								
28	**Section 1301.1(b) Differential**	L23 * L26						**$ (5,316)**

		(1)	(2)
Line No.	Description	Reference	Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		11,428
4	Total Customer Revenue		2,984,605
5	Shopping Revenue		1,107,648
6	LPC REVENUE	L3 / (L4 + L5)	0.002793
7	GROSS RECEIPTS TAX		(0.059000)
8	UNCOLLECTIBLE EXPENSES	D-10	(0.009708)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.002397)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.931688
13			
14	STATE INCOME TAX RATE		8.490%
15			
16	STATE INCOME TAX FACTOR	-	(0.079100)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.852588
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	-	(0.179043)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.673544
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.484684
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	25.814%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		8.490%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.084900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.915100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.192171)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.722929
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.383262
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	27.707%

PECO Exhibit MJT-3:

Principal Accounting Exhibit – Historic Test Year ended December 31, 2023

Line No.	Description	Reference	(1) Present Rates	(2) Revenue Increase	(3) Total
1	**MEASURE OF VALUE**				
□	Utility Plant	C-2	$9,276,705		$9,276,705
□	Accumulated Depreciation	C-3	2,139,325		2,139,325
□	Common Plant - Net of Accum Depr	C-8	435,320		435,320
□	Net Plant in service	L2 - L3 + L4	$7,572,701		$7,572,701
□					
□	Working Capital	C-1	$219,251		$219,251
□	Accum Deferred Income Taxes	C-1	(613,793)		(613,793)
□	Customer Deposits	C-1	(57,291)		(57,291)
10	Customer Advances for Construction	C-1	(2,889)		(2,889)
11	Materials and Supplies	C-1	30,350		30,350
1□	Accum Deferred Income Taxes - Reg Liability	C-1	(288,276)		(288,276)
1□					
1□	TOTAL RATE BASE	SUM L5 to L12	$6,860,054		$6,860,054
1□					
1□	**OPERATING REVENUES AND EXPENSES**				
1□	Base Customer Charges	D-5	$1,743,302	$131,874	$1,875,176
1□	Electric Cost Revenue	D-5	$1,141,275		1,141,275
1□	Other Operating Revenues	D-5	$50,097	551	50,648
□0	Total Revenues	SUM L17 to L19	$2,934,674	$132,425	$3,067,099
□1					
□□	Operating Expenses	D-1	$2,471,689	$9,377	$2,481,066
□□					
□□	OIBIT	L20 - L22	$462,986	$123,048	$586,033
□□					
□□	Income Taxes @ Eff Inc Tax Rate	D-18	($17,056)		($17,056)
□□	Income Taxes @ Statutory Rates	D-18		($34,579)	($34,579)
□□					
□□	NET OPERATING INCOME	SUM L24 to L27	$445,929	$88,469	$534,398
□0					
□1	RATE OF RETURN	L29 / L14	6.50%		7.79%
□□					
□□	**REVENUE INCREASE REQUIRED**				
□□	Rate of Return at Present Rates	L31	6.50%		
□□					
□□	Rate of Return Required	B-7	7.79%		
□□					
□□	Change in ROR	L36 - L34	1.29%		
□□					
□0	Change in Operating Income	L14 * L38	$88,469		
□1					
□□	Gross Revenue Conversion Factor	D-19	1.491		
□□					
□□	Change in Revenues	L40 * L42	$131,874		
□□					
□□	**RETURN ON COMMON EQUITY**				
□□	Common Equity Ratio	B-7	52.99%		
□□	Common Equity Rate Base	L14 * L47	$3,635,143		
□□	NET OPERATING INCOME	L29	$445,929		
□0	Synchronized Interest Expense	D-18	$136,515		
□1	NET OPERATING INCOME - COMMON EQUITY	L49 - L50	$309,414		
□□	RATE OF RETURN ON COMMON EQUITY	L51 / L48	8.51%		

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$16,364,069
3	Construction Work In Progress (107)		884,592
4	Total Utility Plant	L2 + L3	$17,248,662
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		4,108,917
6	Net Utility Plant	L4 - L5	$13,139,744
7			
8	**Other Property and Investments**		
9	Non-Utility Property (121)		$13,257
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,321
11	Invest in Assoc Company (123)		(20,325)
12	Other Investments (124-129, 175-176)		27,679
13	Total Other Property and Investments	SUM L9 to L12	$19,290
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments (131-136)		$44,405
17	Customer Accounts Receivable (142)		342,083
18	Other Accounts Receivable (143)		116,656
19	Accum. Prov. for Uncollectible (144)		(102,633)
20	Receivables from Assoc. Comp. (146)		2,361
21	Fuel Stock (151)		50,589
22	Plant Materials & Supplies (154)		67,119
23	Prepayments (165)		19,523
24	Accrued Utility Revenues (173)		184,653
25	Miscellaneous Current & Accrued Assets (174)		38,560
26	Total Current and Accrued Assets	SUM L16 to L25	$763,315
27			
28	**Deferred Debits**		
29	Unamortized Debt Expense (181)		$43,162
30	Other Regualtory Assets (182.3)		919,812
31	Miscellaneous Deferred Debits (186)		717,805
32	Unamortized Loss on Reacquired Debt (189)		
33	Accumulated Deferred Income Taxes (190)		278,338
34	Total Deferred Debits	SUM L29 to L33	$1,959,118
35			
36	**TOTAL ASSETS**	L6+L13+L26+L34	$15,881,468

		(1)	(2)
Line No.	Description	Reference	Total - PECO
37	**Proprietary Capital**		
38	Common Stock Issued (201)		$1,423,004
39	Preferred Stock Issued (204)		
40	Other Paid-In Capital (208-211)		2,627,435
41	Capital Stock Expense (214)		(87)
42	Retained Earnings (215, 215.2, 216)		5,436,968
43	Unappropriated Undistributed Subsidiary Earnings (216.1)		(3,419,976)
44	Accum Other Comprehensive Income (219)		2,176
45	Total Propriety Capital & Margins	SUM L38 to L44	$6,069,521
46			
47	**Long Term Debt**		
48	Bonds (221)		$5,200,000
49	Advances from Associated Companies (223)		184,419
50	Other Long-Term Debt (224)		
51	Unamortized Premium on LTD (225)		
52	Unamortized Discount on LTD (226)		(24,352)
53	Total Long-Term Debt	SUM L48 to L52	$5,360,066
54			
55	**Other Non-Current Liabilities**		
56	Obligations under Capital Leases (227)		
57	Accum. Prov for Injuries & Damages (228.2)		$36,915
58	Accum. Prov for Pensions & Benefits (228.3)		303,421
59	Accum. Miscellaneous Operating Prov (228.4)		16,430
60	Asset Retirement Obligation (230)		26,348
61	Total Other Non-Current Liabilities	SUM L56 to L60	$383,115
62			
63	**Current and Accrued Liabilities**		
64	Notes Payable (231)		$164,783
65	Accounts Payable (232)		508,750
66	Notes Payable to Assoc. Companies (233)		
67	Accounts Payable to Assoc. Companies (234)		40,237
68	Customer Deposits (235)		78,872
69	Taxes Accrued (236)		64,430
70	Interest Accrued (237)		49,878
71	Dividends Declared (238)		
72	Tax Collections Payable (241)		38
73	Misc Current & Accrued Liabilities (242)		151,816
74	Total Current & Accrued Liabilities	SUM L64 to L73	$1,058,804
75			
76	**Other Deferred Credits**		
77	Customer Advances for Construction (252)		$4,172
78	Other Deferred Credits (253)		1,521
79	Other Regulatory Liabilities (254)		404,351
80	Deferred Investment Tax Credit (255)		332
81	Unamortized Gain on Reacquired Debt (257)		788
82	Accumulated Deferred Income Taxes (281-283)		2,598,799
83	Total Other Deferred Credits	SUM L77 to L82	$3,009,962
84			
85	**TOTAL LIABILITIES AND OTHER CREDITS**	L45+L53+L61+L74+L83	$15,881,468

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Line No.	Category	Description	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$1,544,095		$1,544,095
2		Electric Cost Revenue	1,141,363		1,141,363
3		Transmission - All Classes	209,772		209,772
4		Other Revenues	306,983	$256,885	50,097
5		Total Operating Revenues	$3,202,212	$256,885	$2,945,327
6					
7	**Total Operating Expenses**	Operation & Maintenance Expenses	$2,106,374	$79,962	$2,026,412
8		Depreciation & Amortization Expense	302,761	44,619	258,142
9		Amortization of Regulatory Expense			
10		Taxes Other Than Income Taxes - Other	193,733	4,284	189,450
11		Total Operating Expenses	$2,602,868	$128,865	$2,474,003
12					
13	**Net Utility Operating Income Before Income Tax**		**$599,344**	**$128,020**	**$471,324**

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	440.0	$875,808		$875,808
2			Residential - House Heating	440.1	156,268		156,268
3			C & I Small	442.0	292,195		292,195
4			C & I Large	442.1	190,530		190,530
5			Street Lighting	444.0	8,117		8,117
6			Railroads & Railways	446.0	21,011		21,011
7			Intercompany	448.0	166		166
8			Transmission - All Classes		209,772		209,772
9			Sub-total - Customer & Distribution Revenues		$1,753,867		$1,753,867
10							
11		Electric Cost Revenue	Residential	440.0	$745,840		$745,840
12			Residential - House Heating	440.1	176,253		176,253
13			C & I Small	442.0	193,399		193,399
14			C & I Large	442.1	24,714		24,714
15			Street Lighting	444.0	1,069		1,069
16			Sales for Resale	447.0	87		87
17			Intercompany	448.0			
18			Sub-total - Electric Cost Revenue		$1,141,363		$1,141,363
19							
20		Other Operating Revenues	Forfeited Discounts	450.0	$16,337		$16,337
21			Miscellaneous Service Revenues	451.0	4,933		4,933
22			Rent For Electric Property	454.0	32,628	$10,633	21,995
23			Other Electric Revenues	456.0	6,833		6,833
24			Transmission of Electricity for Others	456.1	246,253	246,253	
25			Sub-total - Other Operating Revenues		$306,983	$256,885	$50,097
26							
27			**TOTAL OPERATING REVENUES**		$3,202,212	$256,885	$2,945,327
28							

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
29	**Operating Expenses**	Operation & Maintenance Expenses	Purchased Power	555.0	$1,073,543		$1,073,543
30			Operation & Supervision	560.0	9,058	$9,058	
31			Load Dispatching	561.0			
32			Scheduling, System Control & Dispatch	561.4	99,062		99,062
33			Transmission Service Studies	561.6			
34			Generation Service Studies	561.7			
35			Reliability, Planning & Standard Development	561.8	97,936		97,936
36			Station Expense	562.0	341	341	
37			Overhead Lines	563.0	434	434	
38			Underground Lines Expense	564.0			
39			Miscellaneous Expense	566.0	14,504	14,504	
40			Rents	567.0	12,104	12,104	
41			Maintenance of Structures	569.0	19	19	
42			Maintenance of Computer Hardware	569.1	99	99	
43			Maintenance of Computer Software	569.2	99	99	
44			Maintenance of Communication Equipment	569.3	127	127	
45			Maintenance of Station Equipment	570.0	9,137	9,137	
46			Maintenance of Overhead Lines	571.0	8,378	8,378	
47			Maintenance of Underground Lines	572.0	76	76	
48			Maintenance of Misc Transmission Plant	573.0	7,720	7,720	
49			Operation & Supervision	580.0	1,231		1,231
50			Load Dispatching	581.0			
51			Station Expenses	582.0	678		678
52			Overhead Lines Expenses	583.0	14,558		14,558
53			Underground Lines Expense	584.0	10,968		10,968
54			Meter Expenses	586.0	6,495		6,495
55			Customer Installations Expense	587.0	12,458		12,458
56			Miscellaneous Expense	588.0	79,400		79,400
57			Rents	589.0	3,535		3,535
58			Maintenance of Structures	591.0	4,942		4,942
59			Maintenance of Station Equipment	592.0	17,606		17,606
60			Maintenance of Overhead Lines	593.0	146,409		146,409
61			Maintenance of Underground Lines	594.0	36,176		36,176

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
62			Maintenance of Line Transformers	595.0	2,061		2,061
63			Maintenance of Street Lighting & Signal Systems	596.0	1,539		1,539
64			Maintenance of Misc. Distribution	598.0	17,980		17,980
65			Supervision	901.0			
66			Meter Reading	902.0	622		622
67			Customer Records and Collection	903.0	94,383		94,383
68			Uncollectible Accounts	904.0	42,082		42,082
69			Miscellaneous Customer Accounts	905.0	3,726		3,726
70			Customer Assistance	908.0	92,332		92,332
71			Informational & Instructional	909.0	897		897
72			Miscellaneous Customer & Informational	910.0	738		738
73			Demonstrating & Selling	912.0	318		318
74			Miscellaneous Sales	916.0			
75			Administrative and General Salaries	920.0	28,386	3,923	24,463
76			Office Supplies and Expenses	921.0	6,136	1,118	5,018
77			Administrative Expenses Transferred-Credit	922.0			
78			Outside Service Employed	923.0	96,807	10,030	86,778
79			Property Insurance	924.0	856	95	761
80			Injuries & Damages	925.0	17,418	46	17,372
81			Employee Pensions and Benefits	926.0	17,303	1,638	15,665
82			Regulatory Commission Expenses	928.0	7,776	63	7,712
83			Duplicate Charges-Credit	929.0	(1,475)	(132)	(1,343)
84			Miscellaneous General Expenses	930.2	2,923	628	2,295
85			Maintenance of General Plant	935.0	6,477	458	6,019
86				Sub-total - O&M Expenses	$2,106,374	$79,962	$2,026,412
87							

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	HTY Amount	Non-Jurisdictional	Jurisdictional
88		Depreciation & Amortization Expense	Depreciation & Amortization Expense	403.0	$251,766	$35,462	$216,304
89				404.0	50,995	9,157	41,838
90			Sub-total - Depreciation & Amortization Expense		$302,761	$44,619	$258,142
91							
92		Amortization of Regulatory Expense	Amortization of Regulatory Expense	407.3			
93			Sub-total - Amortization of Regulatory Expense				
94							
95		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	408.1	$193,733	$4,284	$189,450
96			Sub-total -Taxes Other Than Income Taxes - Other		$193,733	$4,284	$189,450
97							
98			**TOTAL OPERATING EXPENSES**		$2,602,868	$128,865	$2,474,003
99							
100			**NET UTILITY OPERATING INCOME BEFORE INCOME TAX**		**$599,344**	**$128,020**	**$471,324**
101							

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	440.0	$875,808		$875,808
2			Residential - House Heating	440.1	156,268		156,268
3			C & I Small	442.0	292,195		292,195
4			C & I Large	442.1	190,530		190,530
5			Railroads & Railways	446.0	8,117		8,117
6			Street Lighting	444.0	21,011		21,011
7			Intercompany	448.0	166		166
8			Transmission - All Classes		209,772		209,772
9			Sub-total - Customer & Distribution Revenue		$1,753,867		$1,753,867
10							
11		**Electric Cost Revenue**	Residential	440.0	$745,840		$745,840
12			Residential - House Heating	440.1	176,253		176,253
13			C & I Small	442.0	193,399		193,399
14			C & I Large	442.1	24,714		24,714
15			Railroads & Railways	444.0			
16			Street Lighting	446.0	1,069		1,069
17			Sales for Resale	447.0	87		87
18			Intercompany	448.0			
19			Sub-total - Electric Cost Revenue		$1,141,363		$1,141,363
20							
21			**TOTAL OPERATING REVENUE**		$2,895,230		$2,895,230
22							
23	**OTHER REVENUE**	**Other Operating Revenue**	Forfeited Discounts	450.0	$16,337		$16,337
24			Miscellaneous Service Revenues	451.0	4,933		4,933
25			Sub-total - Other Operating Revenue		$21,270		$21,270
26							
27		**Other Electric Revenue**	Rent For Electric Property	454.0	$32,628	$10,633	$21,995
28			Other Electric Revenues	456.0	6,833		6,833
29			Transmission of Electricity for Others	456.1	246,253	246,253	
30			Sub-total - Other Electric Revenue		$285,713	$256,885	$28,828
31							
32			**TOTAL OTHER REVENUE**		$306,983	$256,885	$50,097
33							
34			**TOTAL REVENUE**		**$3,202,212**	**$256,885**	**$2,945,327**

Line No.	Category	Description	Account	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**POWER SUPPLY EXPENSES**	Power Supply	Purchased Power	555.0	$1,073,543		$1,073,543
2			**TOTAL POWER SUPPLY EXPENSES**		$1,073,543		$1,073,543
3							
4	**TRANSMISSION EXPENSE**	Transmission Operations	Operation & Supervision	560.0	$9,058	$9,058	
5			Load Dispatching	561.0			
6			Scheduling, System Control & Dispatch	561.4	99,062		99,062
7			Transmission Service Studies	561.6			
8			Generation Service Studies	561.7			
9			Reliability, Planning & Standard Development	561.8	97,936		97,936
10			Station Expense	562.0	341	341	
11			Overhead Lines	563.0	434	434	
12			Underground Lines Expense	564.0			
13			Miscellaneous Expense	566.0	14,504	14,504	
14			Rents	567.0	12,104	12,104	
15			Sub-total Transmission Operations	SUM L4 to L14	$233,439	$36,442	$196,997
16							
17		Transmission Maintenance	Maintenance of Structures	569.0	$19	$19	
18			Maintenance of Computer Hardware	569.1	99	99	
19			Maintenance of Computer Software	569.2	99	99	
20			Maintenance of Communication Equipment	569.3	127	127	
21			Maintenance of Station Equipment	570.0	9,137	9,137	
22			Maintenance of Overhead Lines	571.0	8,378	8,378	
23			Maintenance of Underground Lines	572.0	76	76	
24			Maintenance of Misc Transmission Plant	573.0	7,720	7,720	
25			Sub-total Transmission Maintenance	SUM L17 to L24	$25,654	$25,654	
26							
27			**TOTAL TRANSMISSION EXPENSE**	L15 + L25	$259,093	$62,096	$196,997
28							
29	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation & Supervision	580.0	$1,231		$1,231
30			Load Dispatching	581.0			
31			Station Expenses	582.0	678		678
32			Overhead Lines Expenses	583.0	14,558		14,558
33			Underground Lines Expense	584.0	10,968		10,968
34			Meter Expenses	586.0	6,495		6,495
35			Customer Installations Expense	587.0	12,458		12,458
36			Miscellaneous Expense	588.0	79,400		79,400
37			Rents	589.0	3,535		3,535
38			Sub-total Distribution Operations	SUM L29 to L37	$129,321		$129,321
39							
40		Distribution Maintenance	Maintenance of Structures	591.0	4,942		4,942
41			Maintenance of Station Equipment	592.0	17,606		17,606
42			Maintenance of Overhead Lines	593.0	146,409		146,409
43			Maintenance of Underground Lines	594.0	36,176		36,176
44			Maintenance of Line Transformers	595.0	2,061		2,061
45			Maintenance of Street Lighting & Signal Systems	596.0	1,539		1,539
46			Maintenance of Misc. Distribution	598.0	17,980		17,980

Line No.	Category	Description	Account	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
47			Sub-total Distribution Maintenance	SUM L40 to L46	$226,712		$226,712
48							
49			**TOTAL DISTRIBUTION EXPENSE**	L38 + L47	$356,034		$356,034
50							
51	**CUSTOMER ACCOUNTS**	Customer Accounts	Supervision	901.0			
52			Meter Reading	902.0	622		622
53			Customer Records and Collection	903.0	94,383		94,383
54			Uncollectible Accounts	904.0	42,082		42,082
55			Miscellaneous Customer Accounts	905.0	3,726		3,726
56			**TOTAL CUSTOMER ACCOUNTS**	SUM L51 to L55	$140,812		$140,812
57							
58	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$92,332		$92,332
59			Informational & Instructional	909.0	897		897
60			Miscellaneous Customer & Informational	910.0	738		738
61			**TOTAL CUSTOMER SERVICE & INFORMATION**	SUM L58 to L60	$93,967		$93,967
62							
63	**SALES**	Sales Expense	Demonstrating & Selling	912.0	$318		$318
64			Miscellaneous Sales	916.0			
65			**TOTAL SALES EXPENSE**	SUM L63 to L64	$318		$318
66							
67	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$28,386	$3,923	$24,463
68			Office Supplies and Expenses	921.0	6,136	$1,118	5,018
69			Administrative Expenses Transferred-Credit	922.0			
70			Outside Service Employed	923.0	96,807	$10,030	86,778
71			Property Insurance	924.0	856	$95	761
72			Injuries & Damages	925.0	17,418	$46	17,372
73			Employee Pensions and Benefits	926.0	17,303	$1,638	15,665
74			Regulatory Commission Expenses	928.0	7,776	$63	7,712
75			Duplicate Charges-Credit	929.0	(1,475)	($132)	(1,343)
76			Miscellaneous General Expenses	930.2	2,923	$628	2,295
77			Sub-total A&G Operations	SUM L67 to L76	$176,131	$17,408	$158,722
78							
79		A&G Maintenance	Maintenance of General Plant	935.0	6,477	458	6,019
80							
81			TOTAL ADMINISTRATION & GENERAL	L77 + L79	$182,608	$17,867	$164,741
82							
83			**TOTAL O&M EXPENSE**	L2+L27+L49+L56+L61+L65+L81	$2,106,374	$79,962	$2,026,412
84							
85			TOTAL OPERATIONS EXPENSE		$1,854,007	$54,308	$1,799,699
86			TOTAL MAINTENANCE EXPENSE		252,366	25,654	226,712
87			**TOTAL O&M EXPENSE**	L85 + L86	**$2,106,374**	**$79,962**	**$2,026,412**

Line No.	Category	Description	Description	Account	HTY Amount	Percent to Non-Jurisdiction	Non-Jurisdictional	Jurisdictional
					(1)	(2)	(3)	(4)
1	**Distribution**	**A&G Operations**	Administrative and General Salaries	920.0	$24,463	0.0000%		$24,463
2			Office Supplies and Expenses	921.0	5,018	0.0000%		5,018
3			Administrative Expenses Transferred-Credit	922.0		0.0000%		
4			Outside Service Employed	923.0	86,778	0.0000%		86,778
5			Property Insurance	924.0	761	0.0000%		761
6			Injuries and Damages	925.0	17,372	0.0000%		17,372
7			Employee Pensions and Benefits	926.0	15,665	0.0000%		15,665
8			Regulatory Commission Expenses	928.0	7,712	0.0000%		7,712
9			Duplicate Charges-Credit	929.0	(1,343)	0.0000%		(1,343)
10			Miscellaneous General Expenses	930.2	2,295	0.0000%		2,295
11			Sub-total A&G Operations - Distribution	SUM L1 to L10	$158,722			$158,722
12								
13		**A&G Maintenance**	Maintenance of General Plant	935.0	$5,991	0.0000%		$5,991
14			**ADMINISTRATION & GENERAL - DISTRIBUTION**	L11 + L13	$164,713			$164,713
15								
16	**Transmission**	**A&G Operations**	Administrative and General Salaries	920.0	$3,923	100.0000%	$3,923	
17			Office Supplies and Expenses	921.0	1,118	100.0000%	1,118	
18			Administrative Expenses Transferred-Credit	922.0		100.0000%		
19			Outside Service Employed	923.0	10,030	100.0000%	10,030	
20			Property Insurance	924.0	95	100.0000%	95	
21			Injuries and Damages	925.0	46	100.0000%	46	
22			Employee Pensions and Benefits	926.0	1,638	100.0000%	1,638	
23			Regulatory Commission Expenses	928.0	63	100.0000%	63	
24			Duplicate Charges-Credit	929.0	(132)	100.0000%	(132)	
25			Miscellaneous General Expenses	930.2	628	100.0000%	628	
26			Sub-total A&G Operations - Transmission	SUM L16 to L25	$17,408		$17,408	
27								
28		**A&G Maintenance**	Maintenance of General Plant	935.0	$454	100.0000%	$454	
29			**ADMINISTRATION & GENERAL - TRANSMISSION**	L26 + L28	$17,863		$17,863	
30								

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
31	**General**	**A&G Operations**	Administrative and General Salaries	920.0		12.3730%		
32			Office Supplies and Expenses	921.0		12.3730%		
33			Administrative Expenses Transferred-Credit	922.0		12.3730%		
34			Outside Service Employed	923.0		12.3730%		
35			Property Insurance	924.0		12.3730%		
36			Injuries and Damages	925.0		12.3730%		
37			Employee Pensions and Benefits	926.0		12.3730%		
38			Regulatory Commission Expenses	928.0		12.3730%		
39			Duplicate Charges-Credit	929.0		12.3730%		
40			Miscellaneous General Expenses	930.2		12.3730%		
41			Sub-total A&G Operations - General	SUM L31 to L40				
42								
43		**A&G Maintenance**	Maintenance of General Plant	935.0	$32	12.3730%	$4	$28
44			**ADMINISTRATION & GENERAL - GENERAL**	L41 + L43	$32		$4	$28
45								
46	**TOTAL**	**A&G Operations**	Administrative and General Salaries	920.0	$28,386		$3,923	$24,463
47			Office Supplies and Expenses	921.0	6,136		1,118	5,018
48			Administrative Expenses Transferred-Credit	922.0				
49			Outside Service Employed	923.0	96,807		10,030	86,778
50			Property Insurance	924.0	856		95	761
51			Injuries & Damages	925.0	17,418		46	17,372
52			Employee Pensions and Benefits	926.0	17,303		1,638	15,665
53			Regulatory Commission Expenses	928.0	7,776		63	7,712
54			Duplicate Charges-Credit	929.0	(1,475)		(132)	(1,343)
55			Miscellaneous General Expenses	930.2	2,923		628	2,295
56			Sub-total A&G Operations - TOTAL	SUM L46 to L55	$176,131		$17,408	$158,722
57								
58		**A&G Maintenance**	Maintenance of General Plant	935.0	$6,477		$458	$6,019
59			**ADMINISTRATION & GENERAL - TOTAL**	L56 + L58	$182,608		$17,867	$164,741

Line No.	Description	Percentage	(1) Total	(2) Transmission Elimination	(3) Distribution
1	Public Utility Real Tax (PURTA) Total Expense	17.825%	$6,819	($1,216)	$5,604
2	Use Tax Accrued	17.825%	2,345	(418)	1,927
3	Real Estate Tax Accrued	17.825%	5,664	(1,010)	4,655
4	Miscellaneous TOTI	12.373%	46	(6)	41
5	Payroll Tax Accrued	12.373%	13,211	(1,635)	11,576
6	Gross Receipt Tax		165,647		165,647
7	**Total**		**$193,733**	**($4,284)**	**$189,450**

				(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effectivel nterest Rate	Average Weighted Cost Rate	Annualized Cost	
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $350 - 3.15% - Due 10-15-2025		$350,000		3.29%			
2					6.50%		0.21%		
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		75,000		6.00%			
4					1.39%		0.08%		
5		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%			
6					5.57%		0.34%		
7		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%			
8					3.25%		0.19%		
9		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%			
10					4.64%		0.23%		
11		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.21%			
12					5.57%		0.23%		
13		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%			
14					6.04%		0.23%		
15		PECO - FMB - $650 - 3.90% - Due 3-1-2048		650,000		4.08%			
16					12.07%		0.49%		
17		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%			
18					6.04%		0.19%		
19		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%			
20					6.50%		0.19%		
21		PECO - FMB - $375 - 3.05% - Due 3-15-2051		375,000		3.11%			
22					6.96%		0.22%		
23		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.90%			
24					6.96%		0.20%		
25		PECO - FMB - $350 - 4.60% - Due 5-15-2052		350,000		4.71%			
26					6.50%		0.31%		
27		PECO - FMB - $425 - 4.375% - Due 8-15-2052		425,000		4.46%			
28					7.89%		0.35%		
29		PECO - FMB - $575 - 4.90% - Due 6-15-2033		575,000		5.03%			
30					10.68%		0.54%		
31									
32		Sub-total Mortgage Bonds	SUM L1 to L30	$5,200,000	96.57%		4.00%		
33									
34	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.46%			
35					1.50%		0.11%		
36		PECO - TOPRS - $0.8 - Var (6.75%) - Due 4-6-2028		805		6.75%			
37					0.01%				
38		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%			
39					1.91%		0.11%		
40									
41		Sub-total Capital Securities	SUM L34 to L39	$184,419	3.43%		0.22%		
42									
43		Total Long-Term Debt	L32 + L41	$5,384,419	100.00%		4.22%		
44									
45		Adjustments for Tenders & Calls		(864)					
46									
47		Net Long-Term Debt	L43 + L45	$5,383,555					
48									
49		Annualized Cost		227,222					
50									
51		Adjustment for Tenders & Calls Reacquired		341					
52									
53		**Total**	L49 + L51	$227,563					4.23%

	(1)	(2)	(3)	(4)
Line No.	Description	Capitalization	Capitalization Ratio	Embedded Cost	Return %
1					
2	Long-Term Debt	$5,383,555	47.01%	4.23%	1.99%
3					
4	Common Equity	$6,069,521	52.99%	10.95%	5.80%
5					
6	Total	$11,453,075	100.00%		7.79%

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	HTY Amount	Non-Jurisdictional	Jurisdictional
1	Utility Plant	C-2	$11,301,773	$2,025,068	$9,276,705
2	Accumulated Depreciation	C-3	2,763,339	624,014	2,139,325
3	Common Plant	C-8	435,320		435,320
4	**Net Plant in Service**	L1 - L2 + L3	$8,973,755	$1,401,054	$7,572,701
5					
6	Working Capital	C-4	$219,251		$219,251
7	Accumulated Deferred Income Taxes	C-6	(613,793)		(613,793)
8	Customer Deposits	C-7	(57,291)		(57,291)
9	Customer Advances for Construction	C-9	(2,889)		(2,889)
10	Material & Supplies	C-11	30,350		30,350
11	ADIT - Reg Liability	C-12	(288,276)		(288,276)
12	**Total Measures of Value**	SUM L4 to L11	$8,261,108	$1,401,054	$6,860,054

Line No.	Category	Account	Reference	HTY Amount	Non-Jurisdictional	Jurisdictional
			(1)	(2)	(3)	(4)
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents		$163	$20	$143
3		E303 - Misc Intangible Plant		163,322	27,676	135,646
4		Sub-total Intangible Plant	SUM L1 to L3	$163,485	$27,696	$135,789
5						
6	**Transmission Plant**	E350 - Land and Land Rights		$75,731	$75,731	
7		E352 - Structures and Improvements		101,496	101,496	
8		E353 - Station Equipment		1,009,734	1,009,734	
9		E354 - Towers and Fixtures		291,316	291,316	
10		E355 - Poles and Fixtures		29,596	29,596	
11		E356 - Overhead Conductors, Devices		278,178	278,178	
12		E357 - Underground Conduit		42,173	42,173	
13		E358 - Undergrnd Conductors, Devices		126,219	126,219	
14		E359 - Roads and Trails		2,621	2,621	
15		E359.1 - ARO Costs Transmission Plt		504	504	
16		Sub-total Transmission Plant	SUM L6 to L15	$1,957,570	$1,957,570	
17						
18	**Distribution Plant**	E360 - Land and Land Rights		$54,159		$54,159
19		E361 - Structures and Improvements		208,819		208,819
20		E362 - Station Equipment		1,247,093		1,247,093
21		E364 - Poles, Towers and Fixtures		1,161,298		1,161,298
22		E365 - Overhead Conductors, Devices		1,948,621		1,948,621
23		E366 - Underground Conduit		765,407		765,407
24		E367 - Undergrnd Conductors, Devices		1,801,734		1,801,734
25		E368 - Line Transformers		774,629		774,629
26		E369 - Services		467,518		467,518
27		E370 - Meters		347,017		347,017
28		E371 - Installs on Customer Premiss		13,772		13,772
29		E373 - Street Lighting, Signal Systems		66,273		66,273
30		E374 - ARO Costs Distribution Plant		2,693		2,693
31		Sub-total Distribution Plant	SUM L18 to L30	$8,859,034		$8,859,034
32						
33	**General Plant**	E389 - Land and Land Rights		$1,063	$132	$932
34		E390 - Structures and Improvements		50,959	6,305	44,654
35		E391 - Office Furniture, Equipment		30,578	3,783	26,794
36		E392 - Transportation Equipment				
37		E393 - Stores Equipment		45	6	39
38		E394 - Tools, Shop, Garage Equipment		53,044	6,563	46,481
39		E395 - Laboratory Equipment		255	32	224
40		E396 - Power Operated Equipment				
41		E397 - Communication Equipment		183,070	22,651	160,419
42		E398 - Miscellaneous Equipment		712	88	624
43		E399 - Other Tangible Property				
44		E399.1 - ARO Costs General Plant		1,958	242	1,716
45		Sub-total General Plant	SUM L33 to L44	$321,685	$39,802	$281,883
46						
47		**Total**	L4+L16+L31+L45	**$11,301,773**	**$2,025,068**	**$9,276,705**

(1)

Line No.	Category	Account	Additions to Plant
1	**Intangible Plant**	E303 - Misc Intangible Plant	
2		Sub-total Intangible Plant	
3			
4	**Transmission Plant**	E350 - Land and Land Rights	
5		E352 - Structures and Improvements	
6		E353 - Station Equipment	
7		E354 - Towers and Fixtures	
8		E355 - Poles and Fixtures	
9		E356 - Overhead Conductors, Devices	
10		E357 - Underground Conduit	
11		E358 - Undergrnd Conductors, Devics	
12		E359 - Roads and Trails	
13		Sub-total Transmission Plant	
14			
15	**Distribution Plant**	E361 - Structures and Improvements	
16		E362 - Station Equipment	
17		E364 - Poles, Towers and Fixtures	
18		E365 - Overhead Conductors, Devices	
19		E366 - Underground Conduit	
20		E367 - Undergrnd Conductors, Devics	
21		E368 - Line Transformers	
22		E369 - Services	
23		E370 - Meters	
24		E373 - Street Lighting,Signal Systm	
25		Sub-total Distribution Plant	
26			
27	**General Plant**	E390 - Structures and Improvements	
28		E391 - Office Furniture, Equipment	
29		E394 - Tools, Shop, Garage Equipmnt	
30		E397 - Communication Equipment	
31		E398 - Miscellaneous Equipment	
32		Sub-total General Plant	
33			
34		**Total**	

(1)

Line No.	Category	Account	Plant Retirements
1	**Intangible Plant**	E303 - Misc Intangible Plant	
2		Sub-total Intangible Plant	
3			
4	**Transmission Plant**	E352 - Structures and Improvements	
5		E353 - Station Equipment	
6		E354 - Towers and Fixtures	
7		E355 - Poles and Fixtures	
8		E356 - Overhead Conductors, Devices	
9		E357 - Underground Conduit	
10		E358 - Undergrnd Conductors, Devics	
11		E359.1 - ARO Costs Transmission Plt	
12		Sub-total Transmission Plant	
13			
14	**Distribution Plant**	E361 - Structures and Improvements	
15		E362 - Station Equipment	
16		E364 - Poles, Towers and Fixtures	
17		E365 - Overhead Conductors, Devices	
18		E366 - Underground Conduit	
19		E367 - Undergrnd Conductors, Devics	
20		E368 - Line Transformers	
21		E369 - Services	
22		E370 - Meters	
23		E373 - Street Lighting,Signal Systm	
24		E374 - ARO Costs Distribution Plt	
25		Sub-total Distribution Plant	
26			
27	**General Plant**	E390 - Structures and Improvements	
28		E391 - Office Furniture, Equipment	
29		E393 - Stores Equipment	
30		E394 - Tools, Shop, Garage Equipmnt	
31		E395 - Laboratory Equipment	
32		E397 - Communication Equipment	
33		E398 - Miscellaneous Equipment	
34		E399.1 - ARO Costs General Plt	
35		Sub-total General Plant	
36			
37		**Total**	

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	HTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	E301 - Organization Costs						
2								
3		E302 - Franchises and Consents	$163	100.00%	$163	87.63%	$143	$20
4			$163		$163		$143	$20
5								
6		E303 - Misc Intangible Plant	$163,322	100.00%	$163,322	83.05%	$135,646	$27,676
7			$163,322		$163,322		$135,646	$27,676
8								
9		Sub-total Intangible Plant	$163,485		$163,485		$135,789	$27,696
10								
11	**Transmission Plant**	E350 - Land and Land Rights	$75,731	100.00%	$75,731			$75,731
12			$75,731		$75,731			$75,731
13								
14		E352 - Structures and Improvements	101,496	100.00%	101,496			101,496
15			101,496		101,496			101,496
16								
17		E353 - Station Equipment	1,009,734	100.00%	1,009,734			1,009,734
18			1,009,734		1,009,734			1,009,734
19								
20		E354 - Towers and Fixtures	291,316	100.00%	291,316			291,316
21			291,316		291,316			291,316
22								
23		E355 - Poles and Fixtures	29,596	100.00%	29,596			29,596
24			29,596		29,596			29,596
25								
26		E356 - Overhead Conductors, Devices	278,178	100.00%	278,178			278,178
27			278,178		278,178			278,178
28								
29		E357 - Underground Conduit	42,173	100.00%	42,173			42,173
30			42,173		42,173			42,173
31								
32		E358 - Undergrnd Conductors, Devices	126,219	100.00%	126,219			126,219
33			126,219		126,219			126,219
34								
35		E359 - Roads and Trails	2,621	100.00%	2,621			2,621
36			2,621		2,621			2,621
37								
38		E359.1 - ARO Costs Transmission Plt	504	100.00%	504			504
39			504		504			504
40								
41		Sub-total Transmission Plant	$1,957,570		$1,957,570			$1,957,570
42								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	HTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
43	**Distribution Plant**	E360 - Land and Land Rights	$54,159	100.00%	$54,159	100.00%	$54,159	
44			$54,159		$54,159		$54,159	
45								
46		E361 - Structures and Improvements	208,819	100.00%	208,819	100.00%	208,819	
47			208,819		208,819		208,819	
48								
49		E362 - Station Equipment	1,247,093	100.00%	1,247,093	100.00%	1,247,093	
50			1,247,093		1,247,093		1,247,093	
51								
52		E364 - Poles, Towers and Fixtures	1,161,298	100.00%	1,161,298	100.00%	1,161,298	
53			1,161,298		1,161,298		1,161,298	
54								
55		E365 - Overhead Conductors, Devices	1,948,621	100.00%	1,948,621	100.00%	1,948,621	
56			1,948,621		1,948,621		1,948,621	
57								
58		E366 - Underground Conduit	765,407	100.00%	765,407	100.00%	765,407	
59			765,407		765,407		765,407	
60								
61		E367 - Undergrnd Conductors, Devices	1,801,734	100.00%	1,801,734	100.00%	1,801,734	
62			1,801,734		1,801,734		1,801,734	
63								
64		E368 - Line Transformers	774,629	100.00%	774,629	100.00%	774,629	
65			774,629		774,629		774,629	
66								
67		E369 - Services	467,518	100.00%	467,518	100.00%	467,518	
68			467,518		467,518		467,518	
69								
70		E370 - Meters	347,017	100.00%	347,017	100.00%	347,017	
71			347,017		347,017		347,017	
72								
73		E371 - Installs on Customer Premiss	13,772	100.00%	13,772	100.00%	13,772	
74			13,772		13,772		13,772	
75								
76		E373 - Street Lighting, Signal Systems	66,273	100.00%	66,273	100.00%	66,273	
77			66,273		66,273		66,273	
78								
79		E374 - ARO Costs Distribution Plant	2,693	100.00%	2,693	100.00%	2,693	
80		Electric Nonrecoverable 100%						
81			2,693		2,693		2,693	
82								
83		Sub-total Distribution Plant	$8,859,034		$8,859,034		$8,859,034	
84								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	HTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
85	**General Plant**	E389 - Land and Land Rights	$1,063	100.00%	$1,063	87.63%	$932	$132
86			$1,063		$1,063		$932	$132
87								
88		E390 - Structures and Improvements	50,959	100.00%	50,959	87.63%	44,654	6,305
89			50,959		50,959		44,654	6,305
90								
91		E391 - Office Furniture, Equipment	30,578	100.00%	30,578	87.63%	26,794	3,783
92			30,578		30,578		26,794	3,783
93								
94		E393 - Stores Equipment	45	100.00%	45	87.63%	39	6
95			45		45		39	6
96								
97		E394 - Tools, Shop, Garage Equipment	53,044	100.00%	53,044	87.63%	46,481	6,563
98			53,044		53,044		46,481	6,563
99								
100		E395 - Laboratory Equipment	255	100.00%	255	87.63%	224	32
101			255		255		224	32
102								
103		E397 - Communication Equipment	183,070	100.00%	183,070	87.63%	160,419	22,651
104			183,070		183,070		160,419	22,651
105								
106		E398 - Miscellaneous Equipment	712	100.00%	712	87.63%	624	88
107			712		712		624	88
108								
109		E399.1 - ARO Costs General Plant	1,958	100.00%	1,958	87.63%	1,716	242
110			1,958		1,958		1,716	242
111								
112		Sub-total General Plant	$321,685		$321,685		$281,883	$39,802
113								
114								
115		**Total**	**$11,301,773**		**$11,301,773**		**$9,276,705**	**$2,025,068**

Line No.	Category	Account	Reference	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents				
3		E303 - Misc Intangible Plant		$110,293	$16,924	$93,369
4		Sub-total Intangible Plant	SUM L1 to L3	$110,293	$16,924	$93,369
5						
6	**Transmission Plant**	E350 - Land and Land Rights		($0)	($0)	
7		E352 - Structures and Improvements		27,657	27,657	
8		E353 - Station Equipment		240,304	240,304	
9		E354 - Towers and Fixtures		173,286	173,286	
10		E355 - Poles and Fixtures		3,537	3,537	
11		E356 - Overhead Conductors, Devices		92,938	92,938	
12		E357 - Underground Conduit		2,935	2,935	
13		E358 - Undergrnd Conductors, Devices		48,375	48,375	
14		E359 - Roads and Trails		2,193	2,193	
15		E359.1 - ARO Costs Transmission Plt		63	63	
16		Sub-total Transmission Plant	SUM L6 to L15	$591,289	$591,289	
17						
18	**Distribution Plant**	E360 - Land and Land Rights		$310		310
19		E361 - Structures and Improvements		46,767		46,767
20		E362 - Station Equipment		502,907		502,907
21		E364 - Poles, Towers and Fixtures		97,704		97,704
22		E365 - Overhead Conductors, Devices		292,180		292,180
23		E366 - Underground Conduit		180,287		180,287
24		E367 - Undergrnd Conductors, Devices		194,984		194,984
25		E368 - Line Transformers		177,957		177,957
26		E369 - Services		197,180		197,180
27		E370 - Meters		197,011		197,011
28		E371 - Installs on Customer Premises		10,659		10,659
29		E373 - Street Lighting, Signal Systems		33,965		33,965
30		E374 - ARO Costs Distribution Plant		2,141		2,141
31		Sub-total Distribution Plant	SUM L18 to L30	$1,934,051		$1,934,051
32						
33	**General Plant**	E389 - Land and Land Rights				
34		E390 - Structures and Improvements		$16,090	$1,991	$14,099
35		E391 - Office Furniture, Equipment		16,394	2,028	14,366
36		E392 - Transportation Equipment				
37		E393 - Stores Equipment		25	3	22
38		E394 - Tools, Shop, Garage Equipmnt		20,399	2,524	17,875
39		E395 - Laboratory Equipment		225	28	197
40		E396 - Power Operated Equipment				
41		E397 - Communication Equipment		73,081	9,042	64,039
42		E398 - Miscellaneous Equipment		(158)	(20)	(138)
43		E399 - Other Tangible Property				
44		E399.1 - ARO Costs General Plt		1,649	204	1,445
45		Sub-total General Plant	SUM L33 to L44	$127,706	$15,801	$111,905
46						
47		**Total**	L4+L16+L31+L45	**$2,763,339**	**$624,014**	**$2,139,325**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	HTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	E302 - Franchises and Consents						
2								
3								
4		E303 - Misc Intangible Plant	$110,293	100.00%	$110,293	84.66%	$93,369	$16,924
5			$110,293	100.00%	$110,293	84.66%	$93,369	$16,924
6								
7		Sub-total Intangible Plant	$110,293		$110,293		$93,369	$16,924
8								
9	**Transmission Plant**	E350 - Land and Land Rights	($0)	100.00%	($0)			($0)
10			($0)		($0)			($0)
11								
12		E352 - Structures and Improvements	27,657	100.00%	27,657			27,657
13			27,657		27,657			27,657
14								
15		E353 - Station Equipment	240,304	100.00%	240,304			240,304
16			240,304		240,304			240,304
17								
18		E354 - Towers and Fixtures	173,286	100.00%	173,286			173,286
19			173,286		173,286			173,286
20								
21		E355 - Poles and Fixtures	3,537	100.00%	3,537			3,537
22			3,537		3,537			3,537
23								
24		E356 - Overhead Conductors, Devices	92,938	100.00%	92,938			92,938
25			92,938		92,938			92,938
26								
27		E357 - Underground Conduit	2,935	100.00%	2,935			2,935
28			2,935		2,935			2,935
29								
30		E358 - Undergrnd Conductors, Devices	48,375	100.00%	48,375			48,375
31			48,375		48,375			48,375
32								
33		E359 - Roads and Trails	2,193	100.00%	2,193			2,193
34			2,193		2,193			2,193
35								
36		E359.1 - ARO Costs Transmission Plt	63	100.00%	63			63
37			63		63			63
38								
39		Sub-total Transmission Plant	$591,289		$591,289			$591,289
40								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	HTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
41	**Distribution Plant**	E360 - Land and Land Rights	310	100.00%	310	100.00%	310	
42			310		310		310	
43								
44		E361 - Structures and Improvements	$46,767	100.00%	$46,767	100.00%	$46,767	
45			$46,767		$46,767		$46,767	
46								
47		E362 - Station Equipment	502,907	100.00%	502,907	100.00%	502,907	
48			502,907		502,907		502,907	
49								
50		E364 - Poles, Towers and Fixtures	97,704	100.00%	97,704	100.00%	97,704	
51			97,704		97,704		97,704	
52								
53		E365 - Overhead Conductors, Devices	292,180	100.00%	292,180	100.00%	292,180	
54			292,180		292,180		292,180	
55								
56		E366 - Underground Conduit	180,287	100.00%	180,287	100.00%	180,287	
57			180,287		180,287		180,287	
58								
59		E367 - Undergrnd Conductors, Devices	194,984	100.00%	194,984	100.00%	194,984	
60			194,984		194,984		194,984	
61								
62		E368 - Line Transformers	177,957	100.00%	177,957	100.00%	177,957	
63			177,957		177,957		177,957	
64								
65		E369 - Services	197,180	100.00%	197,180	100.00%	197,180	
66			197,180		197,180		197,180	
67								
68		E370 - Meters	197,011	100.00%	197,011	100.00%	197,011	
69			197,011		197,011		197,011	
70								
71		E371 - Installs on Customer Premises	10,659	100.00%	10,659	100.00%	10,659	
72			10,659		10,659		10,659	
73								
74		E373 - Street Lighting, Signal Systems	33,965	100.00%	33,965	100.00%	33,965	
75			33,965		33,965		33,965	
76								
77		E374 - ARO Costs Distribution Plant	2,141	100.00%	2,141	100.00%	2,141	
78								
79			2,141		2,141		2,141	
80								
81		Sub-total Distribution Plant	$1,934,051		$1,934,051		$1,934,051	
82								

Line No.	Description	Account	(1) HTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
83	**General Plant**	E389 - Land and Land Rights						
84								
85								
86		E390 - Structures and Improvements	$16,090	100.00%	$16,090	87.63%	$14,099	$1,991
87			$16,090		$16,090		$14,099	$1,991
88								
89		E391 - Office Furniture, Equipment	16,394	100.00%	16,394	87.63%	14,366	2,028
90			16,394		16,394		14,366	2,028
91								
92		E393 - Stores Equipment	25	100.00%	25	87.63%	22	3
93			25		25		22	3
94								
95		E394 - Tools, Shop, Garage Equipmnt	20,399	100.00%	20,399	87.63%	17,875	2,524
96			20,399		20,399		17,875	2,524
97								
98		E395 - Laboratory Equipment	225	100.00%	225	87.63%	197	28
99			225		225		197	28
100								
101		E397 - Communication Equipment	73,081	100.00%	73,081	87.63%	64,039	9,042
102			73,081		73,081		64,039	9,042
103								
104		E398 - Miscellaneous Equipment	(158)	100.00%	(158)	87.63%	(138)	(20)
105			(158)		(158)		(138)	(20)
106								
107		E399.1 - ARO Costs General Plt	1,649	100.00%	1,649	87.63%	1,445	204
108			1,649		1,649		1,445	204
109								
110		Sub-total General Plant	$127,706		$127,706		$111,905	$15,801
111								
112		**Total**	**$2,763,339**		**$2,763,339**		**$2,139,325**	**$624,014**

Line No.	Category	Account	(1) Reference	(2) HTY Amount
1	**Electric - Intangible Plant**	E303 - Misc Intangible Plant		
2		Sub-total Electric - Intangible Plant		
3				
4	**Electric - Transmission**	E350 - Land and Land Rights		
5		E352 - Structures and Improvements		
6		E353 - Station Equipment		
7		E354 - Towers and Fixtures		
8		E355 - Poles and Fixtures		
9		E356 - Overhead Conductors, Devices		
10		E357 - Underground Conduit		
11		E358 - Undergrnd Conductors, Devics		
12		E359 - Roads and Trails		
13		Sub-total Electric - Transmission	SUM L4 to L12	
14				
15	**Electric - Distribution**	E361 - Structures and Improvements		
16		E362 - Station Equipment		
17		E364 - Poles, Towers and Fixtures		
18		E365 - Overhead Conductors, Devices		
19		E366 - Underground Conduit		
20		E367 - Undergrnd Conductors, Devics		
21		E368 - Line Transformers		
22		E369 - Services		
23		E370 - Meters		
24		E373 - Street Lighting, Signal Systems		
25		Sub-total Electric - Distribution	SUM L15 to L24	
26				
27	**Electric - General Plant**	E390 - Structures and Improvements		
28		E391 - Office Furniture, Equipment		
29		E394 - Tools, Shop, Garage Equipmnt		
30		E397 - Communication Equipment		
31		E398 - Miscellaneous Equipment		
32		Sub-total Electric - General Plant	SUM L27 to L31	
33				
34		**Total**	Lines 2+13+25+32	

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	HTY Expenses	(Lead)/Lag Days	Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			51.95	
4					
5	Expense Lag Days				
6	Payroll (Dist Only)		$157,493	13.58	$2,139,285
7	Pension Expense		6,279	(167.00)	(1,048,654)
8	Commodity Purchased - [A]		1,064,866	35.38	37,669,635
9	Commodity Purchased - [B]		8,677	12.50	108,461
10	PJM Transmission Purchased - By-passable		94,863	12.50	1,185,792
11	PJM Transmission Purchased - Non By-passable		94,454	12.50	1,180,674
12	Other Expenses		533,419	40.07	21,375,196
13	Sub-Total O&M	SUM L6 to L12	$1,960,052		$62,610,389
14					
15	Payment to Suppliers		$1,016,077	38.15	$38,765,019
16					
17	Total O&M and POR Payments	L13 + L15	$2,976,129		$101,375,408
18					
19	O&M Expense / POR Payment Lag Days			34.06	
20					
21	Net Lead/(Lag) Days	L3 - L19		17.89	
22					
23	Days in Current Year			365	
24					
25	Operating Expenses Per Day		$8,154		
26					
27	Working Capital for O&M Expense		$145,844		
28					
29	Average Prepayments		$8,636		
30	Accrued Taxes		$79,460		
31	Interest Payments		($14,688)		
32					
33	**Total Working Capital Requirement**	SUM L27 to L31	**$219,251**		
34					
35	Pro Forma O&M Expense		$2,007,216		
36	Uncollectible Expense		47,164		
37	Pro Forma Cash O&M Expense	L35 - L36	$1,960,052		

Line No.	Description	Reference	(1) Accounts Receivable Balance End of Month	(2) Total Monthly Billing Revenue	(3) A/R Turnover	(4) Days Lag
1	Annual Number of Days					365
2						
3	December		$402,842			
4	January		453,446	$378,637		
5	February		445,195	329,190		
6	March		411,718	303,032		
7	April		408,197	278,953		
8	May		340,718	260,453		
9	June		347,805	288,753		
10	July		409,252	373,500		
11	August		386,093	404,999		
12	September		398,390	381,298		
13	October		308,580	293,722		
14	November		285,129	267,091		
15	December		341,788	320,380		
16						
17	Total	SUM L3 to L15	$4,939,151	$3,880,008		
18						
19	Average A/R Balance		13			
20						
21	Factor		$379,935	$3,880,008	10.21	35.74
22						
23	Collection Days Lag					35.74
24						
25	Billing and Revenue Recording Days Lag					1.00
26						
27	Billing Lag (Average Period)	365 / 12. * 0.5				15.21
28						
29	**Total Revenue Lag Days**	L23 + L25 + L27				**51.95**

Line No.	Category	Description	Reference	Payment Date	Mid-point of Service Period	Expense Amount	(Lead)/Lag Days	Dollar Days
			(1)	(2)	(3)	(4)	(5)	(6)
1	PAYROLL	Union & Non-Union Payroll				$149,170		
2		Paid Twice Per Month					13.58	
3		Weighted Payroll Dollar Value						$2,026,232
4								
5		**Payroll Lag**	SUM L1 to L3			$149,170	**13.58**	$2,026,232
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2023	7/1/2023	$1,408	(167.00)	($235,076)
12								
13		Sub-total	SUM L7 to L11			$1,408		($235,076)
14								
15		**Lag Days for Pension Payment**					**(167.00)**	
16								
17	PURCHASE COMMODITY COSTS	**Payment Lag - Contract Purchases**					**35.38**	
18		**Payment Lag - Spot Market/PJM Purchases**					**12.50**	
19		**Payment Lag - Payment to Suppliers**					**38.15**	
20								
21								
22	OTHER O & M EXPENSES	January				$16,812		$651,478
23		April				26,471		1,077,737
24		July				25,711		1,175,140
25		October				22,699		769,982
26								
27		**Lag Days for Other Expenses**	SUM L22 to L25			$91,693	**40.07**	$3,674,337

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			(1)	(2)	(3)	(4)
Line No.	Months	Description	Number of CDs	Cash Disbursements	Dollar-Days	Expense Lag Days
1	January	Total Disbursements for Month	19,206	$337,934		
2		Total Disbursements for Expenses	1,354	$16,812	$651,478	38.75
3						
4	April	Total Disbursements for Month	33,541	$241,401		
5		Total Disbursements for Expenses	2,115	$26,471	$1,077,737	40.71
6						
7	July	Total Disbursements for Month	29,010	$256,674	-	
8		Total Disbursements for Expenses	1,842	$25,711	$1,175,140	45.70
9						
10	October	Total Disbursements for Month	22,765	$232,356	-	
11		Total Disbursements for Expenses	1,978	$22,699	$769,982	33.92
12	**TOTAL FOUR TEST MONTHS**					
13						
14	**Total Test Month Expense Disbursement**		7,289	$91,693	$3,674,337	**40.07**

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			(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Description	Payment Date	Mid Point Date	Lead/(Lag) Payment Days	Total Payment Amount	Payment Percentage	Payment Amount	Weighted Dollar Days
1	**FEDERAL INCOME TAX**	First Payment	4/17/2023	7/1/2023	75	$75,027	25.00%	$18,757	$1,406,748
2		Second Payment	6/15/2023	7/1/2023	16	75,027	25.00%	18,757	300,106
3		Third Payment	9/15/2023	7/1/2023	(76)	75,027	25.00%	18,757	(1,425,505)
4		Fourth Payment	12/15/2023	7/1/2023	(167)	75,027	25.00%	18,757	(3,132,359)
5		Sub-total FEDERAL INCOME TAX					100.00%	$75,027	($2,851,009)
6									
7	**STATE INCOME TAX**	First Payment	3/15/2023	7/1/2023	108	$2,167	25.00%	$542	$58,502
8		Second Payment	6/15/2023	7/1/2023	16	2,167	25.00%	542	8,667
9		Third Payment	9/15/2023	7/1/2023	(76)	2,167	25.00%	542	(41,168)
10		Fourth Payment	12/15/2023	7/1/2023	(167)	2,167	25.00%	542	(90,461)
11		Sub-total STATE INCOME TAX					100.00%	$2,167	($64,460)
12									
13	**PURTA**	First Payment	5/1/2023	7/1/2023	61	$5,604	100.00%	$5,604	$341,823
14		Subtotal PURTA					100.00%	$5,604	$341,823
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Sub-total PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/9/2023	7/1/2023	22	$4,655	100.00%	$4,655	$102,404
23		Second Payment							
24		Sub-total PA PROPERTY TAX					100.00%	$4,655	$102,404
25									
26	**GROSS RECEIPTS TAX**	First Payment	3/15/2023	7/1/2023	108	$168,371	100.00%	$168,371	$18,184,091
27		Sub-total GROSS RECEIPTS TAX					100.00%	$168,371	$18,184,091

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Total Payment Amount	Weighted Dollar Days	Payment Lead/(Lag) Days	Revenue Lag Days	Net Payment Lead/(Lag) Days	Net Payment Lead/(Lag) Dollars Days	Average Daily Amount for Working Capital
1	FEDERAL INCOME TAX	$75,027	($2,851,009)	(38.00)	51.95	13.95	$1,046,586	$2,867
2	STATE INCOME TAX	$2,167	($64,460)	(29.75)	51.95	22.20	$48,101	$132
3	PURTA	$5,604	$341,823	61.00	51.95	112.95	$632,930	$1,734
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$4,655	$102,404	22.00	51.95	73.95	$344,214	$943
6	GROSS RECEIPTS TAX	$168,371	$18,184,091	108.00	51.95	159.95	$26,930,899	$73,783

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Measures of Value at End of HTY		$6,860,054
2	Long-Term Debt Ratio		47.01%
3	Embedded Cost of Long-Term Debt		4.23%
4	Pro Forma Interest Expense	L1 * L2 * L3	$136,414
5	Days in Curent Year		365
6	Daily Amount	L4 / L5	$374
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days	C-4	51.95
9	Interest Payment Lag Days	L8 - L7	(39.30)
10	**Total Interest for Working Capital**	L6 * L9	**($14,688)**

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Line No.	Description	Reference	(1) EPRI Dues	(2) EEI Dues	(3) EAP Membership Dues	(4) Prepaid Rents & Pole Attachments	(5) PUC Assessment Electric	(6) Land Leasing	(7) Maintenance	(8) IT License & Maintenance	(9) Business Support Systems	(10) VEBA Adjust	(11) Facilities Contracts	(12) IT License & Maintenance	(13) Fleet Activities	(14) IT License & Maintenance	(15) Customer Experience	(16) Postage	(17) Total Prepayment	(18)
1	December					$331	$3,893	$194		$32	$217	$2,394	$0	$96	$448	$71	$327	$1,247		
2	January			$573		788	3,032			($0)	469	2,394	(18)	88	465	51	285	816		
3	February			521		745	2,425			$356	424	2,394	(35)	80	420	170	372	701		
4	March			469		558	1,819	188		$324	333	3,157	157	88	420	254	305	662		
5	April		$304	417	$237	392	1,213		244	$291	544	3,157	139	80	433	112	276	728		
6	May		203	365	138	212	606		195	$259	453	3,157	122	72	428	159	243	731		
7	June		203	313	118	170	0	181	195	$227	226	3,584	105	119	422	294	223	739		
8	July		203	261	99	641	5,155		195	$204	467	3,584	87	111	441	562	277	760		
9	August		203	208	79	453	4,495		195	$240	486	3,584	70	103	441	761	214	685		
10	September		101	156	59	624	5,779	175	195	$201	513	3,775	52	136	399	623	146	664		
11	October		101	104	39	469	5,205		195	$161	491	3,775	35	128	404	561	92	664		
12	November			52	20	284	4,630		195	$405	363	3,775	17	120	438	500	59	712		
13	December			0		234	4,055	168	195	$82	283	4,879	0	153	451	248	573	777		
14																				
15	Total	SUM L1 to L13	$1,319	$3,440	$788	$5,900	$42,307	$906	$1,804	$2,782	$5,270	$43,611	$731	$1,376	$5,610	$4,367	$3,392	$9,886		
16																				
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	67.41%	67.41%	67.41%	67.41%	74.50%	74.50%	74.50%		
18																				
19	Distribution Amount	L15 * L17	$1,319	$3,440	$788	$5,900	$42,307	$906	$1,804	$2,782	$5,270	$29,399	$493	$927	$3,782	$3,254	$2,527	$7,365		
20																				
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13		
22																				
23	Monthly Average	L19 / L21	$101	$265	$61	$454	$3,254	$70	$139	$214	$405	$2,261	$38	$71	$291	$250	$194	$567		
24																				
25	**Rate Case Amount**																			**$8,636**

		(1)	(2)	(3)	(4)	(5)
Line No.	Description	Midpoint of Prior Month Service Period to end of Month	Payment Date Month after Service Period	Additional Weekend or Holidays Extending Payment Date	Lag Days	Average
1	**Contract Purchases in HTY**					
2	January	15.50	19.00	1.00	35.50	
3	February	15.50	19.00	1.00	35.50	
4	March	14.00	19.00	1.00	34.00	
5	April	15.50	19.00	1.00	35.50	
6	May	15.00	19.00	2.00	36.00	
7	June	15.50	19.00	1.00	35.50	
8	July	15.00	19.00	1.00	35.00	
9	August	15.50	19.00	2.00	36.50	
10	September	15.50	19.00	1.00	35.50	
11	October	15.00	19.00	1.00	35.00	
12	November	15.50	19.00	1.00	35.50	
13	December	15.00	19.00	1.00	35.00	
14	**Payment Lag - Contract Purchases**					**35.38**
15						
16	**Spot Market Purchases in HTY and PJM Transmission Purchased**					
17						
18		Service Period	Units	Service Period of Days	Lag Days	Total
19	Service Period Weekly	Wed . to Tues.	Days	7.00		
20						
21	Days from Midpoint to End of Service				3.50	
22						
23	Payment Due on Friday of each Week				9.00	
24	**Payment Lag - Spot Market/PJM Purchases**					**12.50**
25						
26	**Payments to Suppliers**					
27						
28		Payment Lag Days	Revenue Percentage	Weighted Lag Days	Lag Days	Total
29	Residential	25.00	39%	9.72		
30	Nonresidential	20.00	61%	12.23		
31	Weighted Lag Days				21.94	
32						
33	Billing and Revenue Recording Days Lag				1.00	
34						
35	Billing Lag (Average Period)	365 / 12. * 0.5			15.21	
36						
37	Total POR Payment Lag Days	L31 + L33 + L35				**38.15**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - CIAC		($18,074)	100.00%	($18,074)	100.00%	($18,074)
2		ADIT - Common Plant		69,010	100.00%	69,010	63.22%	43,626
3		ADIT - Electric Common Plant		35,732	100.00%	35,732	82.17%	29,362
4		ADIT - Electric Distribution		619,210	100.00%	619,210	100.00%	619,210
5		ADIT - Corp. Alternative Minimum Tax		(60,332)	100.00%	(60,332)	100.00%	(60,332)
6		**Total**	SUM L1 to L5	**$645,546**		**$645,546**		**$613,793**

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Residential	Non-Residential	Total
1	December		$18,802	$31,587	$50,388
2	January		18,976	32,487	51,463
3	February		19,166	33,197	52,363
4	March		19,446	33,844	53,290
5	April		20,077	34,307	54,384
6	May		20,877	35,117	55,994
7	June		21,538	35,642	57,179
8	July		22,060	36,988	59,048
9	August		22,549	38,022	60,571
10	September		22,772	38,782	61,555
11	October		23,058	39,358	62,416
12	November		23,276	39,646	62,922
13	December		23,215	39,988	63,203
14					
15	Total	SUM L1 to L13	$275,812	$468,965	$744,777
16					
17	Average Monthly Balance	L15 / 13	$21,216	$36,074	$57,291
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$21,216
21	Small C&I				30,886
22	Large C&I				5,183
23	Other				5
24					
25	**Total**	SUM L20 to L23			**$57,291**

Line No.	Category	Account	Reference	HTY Amount	Allocated to Non Jurisdiction	Allocated to Jurisdiction
			(1)	(2)	(3)	(4)
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$221	$456
4						
5		E303 - Misc Intangible Plant		$327,035	$106,576	$220,459
6						
7		E389 - Land and Land Rights		$6,783	$2,211	$4,573
8						
9		E390 - Structures and Improvements		$371,001	$120,904	$250,097
10		E391 - Office Furniture, Equipment		71,621	23,340	48,281
11		E392 - Transportation Equipment		196,641	64,083	132,559
12		E393 - Stores Equipment		1,340	437	903
13		E394 - Tools, Shop, Garage Equipmnt		2,552	832	1,720
14		E396 - Power Operated Equipment		185	60	125
15		E397 - Communication Equipment		128,703	41,943	86,761
16		E398 - Miscellaneous Equipment		1,191	388	803
17		E399 - Other Tangible Property				
18		E399.1 - ARO Costs General Plant		1,030	336	694
19		Sub Total - General Plant	SUM L9 to L18	$774,264	$252,322	$521,942
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,108,760	$361,329	$747,430
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$234,192	$76,320	$157,872
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$70,917	$23,111	$47,806
31		E391 - Office Furniture, Equipment		25,843	8,422	17,421
32		E392 - Transportation Equipment		91,386	29,781	61,604
33		E393 - Stores Equipment		375	122	252
34		E394 - Tools, Shop, Garage Equipmnt		961	313	648
35		E396 - Power Operated Equipment		185	60	125
36		E397 - Communication Equipment		38,627	12,588	26,039
37		E398 - Miscellaneous Equipment		839	273	565
38		E399 - Other Tangible Property				
39		E399.1 - ARO Costs General Plant		(331)	(108)	(223)
40		Sub Total - General Plant	SUM L30 to L39	$228,801	$74,563	$154,238
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$462,993	$150,883	$312,110
42						
43		Net Common Plant	L20 - L41	$645,767	$210,446	$435,320
44						
45						
46		Common Plant in Service to Utility	L20	$1,108,760	$361,329	$747,430
47		Common Plant Accum Depreciation to Utility	L41	462,993	150,883	312,110
48		Net Common Plant to Utility	L46 - L47	$645,767	$210,446	$435,320

(1) (2)

Line No.	Description	Reference	Total
1	HTY 13-Month Average		
2	December		$2,662
3	January		2,509
4	February		2,978
5	March		3,239
6	April		3,066
7	May		2,900
8	June		2,423
9	July		2,393
10	August		2,049
11	September		3,859
12	October		3,861
13	November		2,764
14	December		2,855
15			
16	13-Month Total	SUM L2 to L14	$37,557
17			
18			
19	**Average Monthly Balance**	L16 / 13	**$2,889**

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Materials & Supplies	Undistributed Stores Expense	Total
1	HTY 13-Month Average				
2	December		$29,564	($0)	$29,564
3	January		30,031	(191)	29,840
4	February		28,319	(372)	27,947
5	March		26,573	(1,490)	25,083
6	April		26,183	(1,111)	25,072
7	May		26,568	(1,460)	25,108
8	June		27,575	(1,693)	25,882
9	July		28,584	(1,197)	27,387
10	August		33,678	(1,126)	32,553
11	September		34,598	(1,077)	33,522
12	October		34,602	(660)	33,943
13	November		36,708	(686)	36,023
14	December		39,019	0	39,019
15					
16	Total	SUM L2 to L14	$402,003	($11,061)	$390,942
17					
18	Distribution Expense Allocation Factor		100.00%	67.41%	
19					
20	Allocation to Distribution	L16 * L18	$402,003	($7,457)	
21					
22	**Average Monthly Balance**	L20 / 13	$30,923	($574)	**$30,350**

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Line No.	Test Year	Description	Reference	(1) Total Amount	(2) Percent to Utility	(3) Utility Amount	(4) Percent to Distribution	(5) Distribution Amount
1	**HTY**	ADIT - Distribution		$288,276	100.00%	$288,276	100.00%	$288,276
2		ADIT - CIAC			100.00%		100.00%	
3		**Total**	L1 + L2	$288,276		$288,276		$288,276

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Line No.	Category	Description	Reference	(1) Pro Forma Adjusted at Present Rates	(2) Proposed Rate Increase	(3) Adjusted Amounts with Proposed Rate Increase
1	**Operating Revenues**	Residential		$1,637,684		$1,637,684
2		Residential - House Heating		346,968		346,968
3		C & I Small		460,634		460,634
4		C & I Large		200,302		200,302
5		Railroads & Railways		7,554		7,554
6		Street Lighting		21,496		21,496
7		Intercompany		166		166
8		Transmission - All Classes		209,772		209,772
9		Forfeited Discounts		16,337	$551	16,888
10		Miscellaneous Service Revenues		4,933		4,933
11		Rent For Electric Property		21,995		21,995
12		Other Electric Revenues		6,833		6,833
13		Revenue Increase			$131,874	131,874
14		Total Operating Revenues	SUM L1 to L13	$2,934,674	$132,425	$3,067,099
15						
16	**Operating Expenses**	Power Supply		$1,073,543		$1,073,543
17		Transmission Expense		196,997		196,997
18		Distribution Expense		389,248		389,248
19		Customer Accounts Expense		151,121	$1,280	152,401
20		Customer Service and Information Expense		15,422		15,422
21		Sales Expense		328		328
22		Administrative & General		180,559	316	180,875
23		Sub-total O&M Expense	SUM L16 to L22	$2,007,216	$1,596	$2,008,813
24						
25		Depreciation & Amortization Expense		$272,101		$272,101
26		Amortization of Regulatory Expense		(448)		(448)
27		Taxes Other Than Income Taxes - Other		$192,819	$7,781	$200,600
28		Total Operating Expenses	SUM L23 to L27	$2,471,689	$9,377	$2,481,066
29						
30	**Net Operating Income - BIT**		L14 - L28	**$462,986**	**$123,048**	**$586,033**

			(1)	(2)	(3)	(4)
Line No.	Category	Description	Reference	HTY Amount Pre Adjustments	Adjustments Sub-Total	Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential		$1,621,648	$16,036	$1,637,684
2		Residential - House Heating		332,521	14,447	346,968
3		C & I Small		485,594	(24,960)	460,634
4		C & I Large		215,244	(14,942)	200,302
5		Railroads & Railways		8,117	(563)	7,554
6		Street Lighting		22,080	(584)	21,496
7		Intercompany		166		166
8		Transmission - All Classes		209,772		209,772
9		Forfeited Discounts		16,337		16,337
10		Miscellaneous Service Revenues		4,933		4,933
11		Rent For Electric Property		21,995		21,995
12		Other Electric Revenues		6,833		6,833
13		Revenue Increase				
14		Total Operating Revenues	SUM L1 to L13	$2,945,240	($10,565)	$2,934,674
15						
16	**Operating Expenses**	Power Supply		$1,073,543		$1,073,543
17		Transmission Expense		196,997		196,997
18		Distribution Expense		356,034	$33,214	389,248
19		Customer Accounts Expense		140,812	10,308	151,121
20		Customer Service and Information Expense		93,967	(78,545)	15,422
21		Sales Expense		318	10	328
22		Administrative & General		164,741	15,818	180,559
23		Sub-total O&M Expense	SUM L16 to L22	$2,026,412	($19,195)	$2,007,216
24						
25		Depreciation & Amortization Expense		$258,142	$13,959	$272,101
26		Amortization of Regulatory Expense			(448)	(448)
27		Taxes Other Than Income Taxes - Other		189,450	3,370	192,819
28		Total Operating Expenses	SUM L23 to L27	$2,474,003	($2,314)	$2,471,689
29						
30	**Net Operating Income - BIT**		L14 - L28	**$471,236**	**($8,251)**	**$462,986**

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Line No.	Category	Description	Description	(1) HTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act 129 Lost Revenue	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E OPEN	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization
1	**Operating Revenues**	Residential	Elec Cost	$745,840							
2			Cust & Dist	875,808	2,121	3,155	(2,067)	(25,681)		433	38,076
3			Sub-total Residential	$1,621,648	$2,121	$3,155	($2,067)	($25,681)		$433	$38,076
4											
5		Residential - House Heating	Elec Cost	$176,253							
6			Cust & Dist	156,268	1,713	427	(432)	(6,066)		105	18,701
7			Sub-total Residential - House Heating	$332,521	$1,713	$427	($432)	($6,066)		$105	$18,701
8											
9		C & I Small	Elec Cost	$193,399							
10			Cust & Dist	292,195	598		(1,561)	(32,719)		141	8,582
11			Sub-total C & I Small	$485,594	$598		($1,561)	($32,719)		$141	$8,582
12											
13		C & I Large	Elec Cost	$24,714							
14			Cust & Dist	190,530	575		(858)	(17,249)		123	2,467
15			Sub-total C & I Large	$215,244	$575		($858)	($17,249)		$123	$2,467
16											
17		Railroads & Railways	Cust & Dist	$8,117				($563)			
18			Sub-total Railroads & Railways	$8,117				($563)			
19											
20		Street Lighting	Elec Cost	$1,069							
21			Cust & Dist	21,011				(584)			
22			Sub-total Street Lighting	$22,080				($584)			
23											
24		Intercompany	Elec Cost								
25			Cust & Dist	166							
26			Sub-total Interdepartmental	$166							
27											
28		Transmission - All Classes	Transmission - All Classes	$209,772							
29			Sub-total Transmission - All Classes	$209,772							
30											
31		Forfeited Discounts	Forfeited Discounts	$16,337							
32			Sub-total Forfeited Discounts	$16,337							
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues	$4,933							
35			Sub-total Miscellaneous Service Revenues	$4,933							
36											
37		Rent For Electric Property	Rent For Electric Property	$21,995							
38			Sub-total Rent For Electric Property	$21,995							
39											
40		Other Electric Revenues	Other Electric Revenues	$6,833							
41			Sub-total Other Electric Revenues	$6,833							
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**	**$2,945,240**	**$5,007**	**$3,583**	**($4,919)**	**($82,863)**		**$803**	**$67,825**
47											
48	**Operating Expenses**	Power Supply	Purchased Power	$1,073,543							

Line No.	Category	Description	Description	HTY Amount Pre Adjustments	(1) D-5A Revenue Annualization	(2) D-5B CAP Revenue Credits and Adjustments	(3) D-5C Act 129 Lost Revenue	(4) D-5D Energy Efficiency Program Cost Recovery	(5) D-5E OPEN	(6) D-5F Leap Year Adjustment	(7) D-5G Weather Normalization	(8)
49			Sub-total Power Supply	$1,073,543								
50												
51		Transmission Expense	Operation & Supervision									
52			Load Dispatching									
53			Scheduling, System Control & Dispatch	99,062								
54			Transmission Service Studies									
55			Generation Service Studies									
56			Reliability, Planning & Standard Development	97,936								
57			Station Expense									
58			Overhead Lines									
59			Underground Lines Expense									
60			Miscellaneous Expense									
61			Rents									
62			Maintenance of Structures									
63			Maintenance of Computer Hardware									
64			Maintenance of Computer Software									
65			Maintenance of Communication Equipment									
66			Maintenance of Station Equipment									
67			Maintenance of Overhead Lines									
68			Maintenance of Underground Lines									
69			Maintenance of Misc Transmission Plant									
70			Sub-total Transmission Expense	196,997								
71												
72		Distribution Expense	Operation & Supervision	$1,231								
73			Load Dispatching									
74			Station Expense	678								
75			Overhead Lines Expenses	14,558								
76			Underground Lines Expense	10,968								
77			Meter Expenses	6,495								
78			Customer Installations Expense	12,458								
79			Miscellaneous Expense	79,400								
80			Rents	3,535								
81			Maintenance of Structures	4,942								
82			Maintenance of Station Equipment	17,606								
83			Maintenance of Overhead Lines	146,409								
84			Maintenance of Underground Lines	36,176								
85			Maintenance of Line Transformers	2,061								
86			Maintenance of Street Lighting & Signal Systems	1,539								
87			Maintenance of Misc. Distribution	17,980								
88			Sub-total Distribution Expense	$356,034								
89												
90		Customer Accounts	Supervision									
91			Meter Reading	$622								
92			Customer Records and Collection	94,383								
93			Uncollectible Accounts.	42,082								
94			Miscellaneous Customer Accounts Expenses.	3,726								
95			Sub-total Total Customer Accounts	$140,812								
96												

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Line No.	Category	Description	Description	(1) HTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act 129 Lost Revenue	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E OPEN	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization
97		Customer Service and Information	Customer Assistance	$92,332				($78,630)			
98			Informational & Instructional	897							
99			Miscellaneous Customer & Informational	738							
100			Sub-total Customer Service & Information	$93,967				($78,630)			
101											
102		Sales	Demonstrating & Selling	$318							
103			Miscellaneous Sales								
104			Sub-total Sales	$318							
105											
106		Administrative & General	Administrative and General Salaries	$24,463							
107			Office Supplies and Expenses	5,018							
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed	86,778							
110			Property Insurance	761							
111			Injuries & Damages	17,372							
112			Employee Pensions and Benefits	15,665							
113			Regulatory Commission Expenses	7,712							
114			Duplicate Charges-Credit	(1,343)							
115			Miscellaneous General Expenses	2,295							
116			Maintenance of General Plant	6,019							
117			Sub-total Administrative & General	$164,741							
118											
119			**Total O&M Expense**	$2,026,412				($78,630)			
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$258,142							
122			Sub-total Depreciation & Amortization Expense	$258,142							
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense								
125			Sub-total Amortization of Regulatory Expense								
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$189,450							
128			Sub-total Taxes Other Than Income Taxes - Other	$189,450							
129											
130			**Total Operating Expenses**	**$2,474,003**				**($78,630)**			
131											
132	**Net Operating Income Before Income Tax**			**$471,236**	**$5,007**	**$3,583**	**($4,919)**	**($4,233)**		**$803**	**$67,825**

Line No.	Category	Description	Description	(9) D-6 Salary & Wages	(10) D-7 Rate Case Expense	(11) D-8 Adjustments for Employee Benefits	(12) D-9 Adjustments for Pension	(13) D-10 Uncollectible Accounts	(14) D-11 IIJA Reg Asset	(15) D-12 Customer Deposit Interest	(16) D-13 Storm
1	**Operating Revenues**	Residential	Elec Cost								
2			Cust & Dist								
3			Sub-total Residential								
4											
5		Residential - House Heating	Elec Cost								
6			Cust & Dist								
7			Sub-total Residential - House Heating								
8											
9		C & I Small	Elec Cost								
10			Cust & Dist								
11			Sub-total C & I Small								
12											
13		C & I Large	Elec Cost								
14			Cust & Dist								
15			Sub-total C & I Large								
16											
17		Railroads & Railways	Cust & Dist								
18			Sub-total Railroads & Railways								
19											
20		Street Lighting	Elec Cost								
21			Cust & Dist								
22			Sub-total Street Lighting								
23											
24		Intercompany	Elec Cost								
25			Cust & Dist								
26			Sub-total Interdepartmental								
27											
28		Transmission - All Classes	Transmission - All Classes								
29			Sub-total Transmission - All Classes								
30											
31		Forfeited Discounts	Forfeited Discounts								
32			Sub-total Forfeited Discounts								
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues								
35			Sub-total Miscellaneous Service Revenues								
36											
37		Rent For Electric Property	Rent For Electric Property								
38			Sub-total Rent For Electric Property								
39											
40		Other Electric Revenues	Other Electric Revenues								
41			Sub-total Other Electric Revenues								
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**								
47											
48	**Operating Expenses**	Power Supply	Purchased Power								

Line No.	Category	Description	Description	(9) D-6 Salary & Wages	(10) D-7 Rate Case Expense	(11) D-8 Adjustments for Employee Benefits	(12) D-9 Adjustments for Pension	(13) D-10 Uncollectible Accounts	(14) D-11 IIJA Reg Asset	(15) D-12 Customer Deposit Interest	(16) D-13 Storm
49			Sub-total Power Supply								
50											
51		Transmission Expense	Operation & Supervision								
52			Load Dispatching								
53			Scheduling, System Control & Dispatch								
54			Transmission Service Studies								
55			Generation Service Studies								
56			Reliability, Planning & Standard Development								
57			Station Expense								
58			Overhead Lines								
59			Underground Lines Expense								
60			Miscellaneous Expense								
61			Rents								
62			Maintenance of Structures								
63			Maintenance of Computer Hardware								
64			Maintenance of Computer Software								
65			Maintenance of Communication Equipment								
66			Maintenance of Station Equipment								
67			Maintenance of Overhead Lines								
68			Maintenance of Underground Lines								
69			Maintenance of Misc Transmission Plant								
70			Sub-total Transmission Expense								
71											
72		Distribution Expense	Operation & Supervision	$48							
73			Load Dispatching								
74			Station Expense								
75			Overhead Lines Expenses	178							
76			Underground Lines Expense	130							
77			Meter Expenses	125							
78			Customer Installations Expense	300							
79			Miscellaneous Expense	341							
80			Rents								
81			Maintenance of Structures	61							
82			Maintenance of Station Equipment	440							
83			Maintenance of Overhead Lines	2,456							27,972
84			Maintenance of Underground Lines	916							
85			Maintenance of Line Transformers	23							
86			Maintenance of Street Lighting & Signal Systems	5							
87			Maintenance of Misc. Distribution	219							
88			Sub-total Distribution Expense	$5,242							$27,972
89											
90		Customer Accounts	Supervision								
91			Meter Reading	0							
92			Customer Records and Collection	1,661							
93			Uncollectible Accounts.					5,083			
94			Miscellaneous Customer Accounts Expenses.	35					3,572		
95			Sub-total Total Customer Accounts	$1,696				$5,083	$3,572		
96											

Line No.	Category	Description	Description	(9) D-6 Salary & Wages	(10) D-7 Rate Case Expense	(11) D-8 Adjustments for Employee Benefits	(12) D-9 Adjustments for Pension	(13) D-10 Uncollectible Accounts	(14) D-11 IIJA Reg Asset	(15) D-12 Customer Deposit Interest	(16) D-13 Storm
97		Customer Service and Information	Customer Assistance	$75							
98			Informational & Instructional								
99			Miscellaneous Customer & Informational	10							
100			Sub-total Customer Service & Information	$85							
101											
102		Sales	Demonstrating & Selling	$10							
103			Miscellaneous Sales								
104			Sub-total Sales	$10							
105											
106		Administrative & General	Administrative and General Salaries	$1,139							
107			Office Supplies and Expenses								
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed								
110			Property Insurance								
111			Injuries & Damages	82							
112			Employee Pensions and Benefits	2		500	11,829				
113			Regulatory Commission Expenses		1,200						
114			Duplicate Charges-Credit								
115			Miscellaneous General Expenses	2							
116			Maintenance of General Plant	63							
117			Sub-total Administrative & General	$1,288	$1,200	$500	$11,829				
118											
119			**Total O&M Expense**	$8,321	$1,200	$500	$11,829	$5,083		$3,572	$27,972
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense								
122			Sub-total Depreciation & Amortization Expense								
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense						($448)		
125			Sub-total Amortization of Regulatory Expense						($448)		
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other								
128			Sub-total Taxes Other Than Income Taxes - Other								
129											
130			**Total Operating Expenses**	**$8,321**	**$1,200**	**$500**	**$11,829**	**$5,083**	**($448)**	**$3,572**	**$27,972**
131											
132	**Net Operating Income Before Income Tax**			**($8,321)**	**($1,200)**	**($500)**	**($11,829)**	**($5,083)**	**$448**	**($3,572)**	**($27,972)**

Line No.	Category	Description	Description	D-14 Other Adjustments	D-15 OPEN	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
				(17)	(18)	(19)	(20)	(21)	(22)
1	**Operating Revenues**	Residential	Elec Cost						$745,840
2			Cust & Dist					16,036	891,844
3			Sub-total Residential					$16,036	$1,637,684
4									
5		Residential - House Heating	Elec Cost						$176,253
6			Cust & Dist					14,447	170,715
7			Sub-total Residential - House Heating					$14,447	$346,968
8									
9		C & I Small	Elec Cost						$193,399
10			Cust & Dist					(24,960)	267,235
11			Sub-total C & I Small					($24,960)	$460,634
12									
13		C & I Large	Elec Cost						$24,714
14			Cust & Dist					(14,942)	175,589
15			Sub-total C & I Large					($14,942)	$200,302
16									
17		Railroads & Railways	Cust & Dist					($563)	$7,554
18			Sub-total Railroads & Railways					($563)	$7,554
19									
20		Street Lighting	Elec Cost						$1,069
21			Cust & Dist					(584)	20,427
22			Sub-total Street Lighting					($584)	$21,496
23									
24		Intercompany	Elec Cost						
25			Cust & Dist						166
26			Sub-total Interdepartmental						$166
27									
28		Transmission - All Classes	Transmission - All Classes						$209,772
29			Sub-total Transmission - All Classes						$209,772
30									
31		Forfeited Discounts	Forfeited Discounts						$16,337
32			Sub-total Forfeited Discounts						$16,337
33									
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues						$4,933
35			Sub-total Miscellaneous Service Revenues						$4,933
36									
37		Rent For Electric Property	Rent For Electric Property						$21,995
38			Sub-total Rent For Electric Property						$21,995
39									
40		Other Electric Revenues	Other Electric Revenues						$6,833
41			Sub-total Other Electric Revenues						$6,833
42									
43		Revenue Increase	Revenue Increase						
44			Sub-total Revenue Increase						
45									
46			**Total Operating Revenues**					**($10,565)**	**$2,934,674**
47									
48	**Operating Expenses**	Power Supply	Purchased Power						$1,073,543

Line No.	Category	Description	Description	D-14 Other Adjustments	D-15 OPEN	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
				(17)	(18)	(19)	(20)	(21)	(22)
49			Sub-total Power Supply						$1,073,543
50									
51		Transmission Expense	Operation & Supervision						
52			Load Dispatching						
53			Scheduling, System Control & Dispatch						99,062
54			Transmission Service Studies						
55			Generation Service Studies						
56			Reliability, Planning & Standard Development						97,936
57			Station Expense						
58			Overhead Lines						
59			Underground Lines Expense						
60			Miscellaneous Expense						
61			Rents						
62			Maintenance of Structures						
63			Maintenance of Computer Hardware						
64			Maintenance of Computer Software						
65			Maintenance of Communication Equipment						
66			Maintenance of Station Equipment						
67			Maintenance of Overhead Lines						
68			Maintenance of Underground Lines						
69			Maintenance of Misc Transmission Plant						
70			Sub-total Transmission Expense						196,997
71									
72		Distribution Expense	Operation & Supervision					$48	$1,279
73			Load Dispatching						
74			Station Expense						678
75			Overhead Lines Expenses					178	14,736
76			Underground Lines Expense					130	11,098
77			Meter Expenses					125	6,620
78			Customer Installations Expense					300	12,758
79			Miscellaneous Expense					341	79,740
80			Rents						3,535
81			Maintenance of Structures					61	5,002
82			Maintenance of Station Equipment					440	18,046
83			Maintenance of Overhead Lines					30,428	176,837
84			Maintenance of Underground Lines					916	37,092
85			Maintenance of Line Transformers					23	2,084
86			Maintenance of Street Lighting & Signal Systems					5	1,544
87			Maintenance of Misc. Distribution					219	18,198
88			Sub-total Distribution Expense					$33,214	$389,248
89									
90		Customer Accounts	Supervision						
91			Meter Reading					$0	$622
92			Customer Records and Collection					1,661	96,044
93			Uncollectible Accounts.					5,083	47,164
94			Miscellaneous Customer Accounts Expenses.	(43)				3,564	7,290
95			Sub-total Total Customer Accounts	($43)				$10,308	$151,121
96									

Line No.	Category	Description	Description	(17) D-14 Other Adjustments	(18) D-15 OPEN	(19) D-16 Taxes Other Than Income	(20) D-17 Depreciation Annualization	(21) Adjustments Sub-total	(22) Pro Forma Adjusted at Present Rates
97		Customer Service and Information	Customer Assistance					($78,555)	$13,777
98			Informational & Instructional						897
99			Miscellaneous Customer & Informational					10	748
100			Sub-total Customer Service & Information					($78,545)	$15,422
101									
102		Sales	Demonstrating & Selling					$10	$328
103			Miscellaneous Sales						
104			Sub-total Sales					$10	$328
105									
106		Administrative & General	Administrative and General Salaries					$1,139	$25,603
107			Office Supplies and Expenses						5,018
108			Administrative Expenses Transferred-Credit						
109			Outside Service Employed						86,778
110			Property Insurance						761
111			Injuries & Damages					82	17,454
112			Employee Pensions and Benefits					12,331	27,996
113			Regulatory Commission Expenses					1,200	8,912
114			Duplicate Charges-Credit						(1,343)
115			Miscellaneous General Expenses	1,000				1,002	3,298
116			Maintenance of General Plant					63	6,082
117			Sub-total Administrative & General	$1,000				$15,818	$180,559
118									
119			**Total O&M Expense**	$957				($19,195)	$2,007,216
120									
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense				$13,959	$13,959	$272,101
122			Sub-total Depreciation & Amortization Expense				$13,959	$13,959	$272,101
123									
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense					($448)	($448)
125			Sub-total Amortization of Regulatory Expense					($448)	($448)
126									
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other			$3,370		$3,370	$192,819
128			Sub-total Taxes Other Than Income Taxes - Other			$3,370		$3,370	$192,819
129									
130			**Total Operating Expenses**	**$957**		**$3,370**	**$13,959**	**($2,314)**	**$2,471,689**
131									
132	**Net Operating Income Before Income Tax**			**($957)**		**($3,370)**	**($13,959)**	**($8,251)**	**$462,986**

Line No.	Category	Description	Account	(1) HTY Amount Pre Adjustments	(2) D-5D Energy Efficiency Program Expense	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 IIJA Reg Asset
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.	$1,073,543							
2			Sub-total Power Supply	$1,073,543							
3											
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision								
5			561.0 Load Dispatching								
6			561.4 Scheduling, System Control & Dispatch	99,062							
7			561.6 Transmission Service Studies								
8			561.7 Generation Service Studies								
9			561.8 Reliability, Planning & Standard Development	97,936							
10			562.0 Station Expense								
11			563.0 Overhead Lines								
12			564.0 Underground Lines Expense								
13			566.0 Miscellaneous Expense								
14			567.0 Rents								
15			Sub-total Transmission Operations	196,997							
16											
17		**Transmission Maintenance**	569.0 Maintenance of Structures								
18			569.1 Maintenance of Computer Hardware								
19			569.2 Maintenance of Computer Software								
20			569.3 Maintenance of Communication Equipment								
21			570.0 Maintenance of Station Equipment								
22			571.0 Maintenance of Overhead Lines								
23			572.0 Maintenance of Underground Lines								
24			573.0 Maintenance of Misc Transmission Plant								
25			Sub-total Transmission Maintenance								
26											
27			Sub-total TRANSMISSION EXPENSE	196,997							
28											
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision	$1,231	$48						
30			581.0 Load Dispatching								
31			582.0 Station Expense	678	2						
32			583.0 Overhead Lines Expenses	14,558	178						
33			584.0 Underground Lines Expense	10,968	130						
34			586.0 Meter Expenses	6,495	125						
35			587.0 Customer Installations Expense	12,458	300						
36			588.0 Miscellaneous Expense	79,400	341						
37			589.0 Rents	3,535							
38			Sub-total Distribution Operations	$129,321	$1,125						
39											
40		**Distribution Maintenance**	591.0 Maintenance of Structures	$4,942	$61						
41			592.0 Maintenance of Station Equipment	17,606	440						
42			593.0 Maintenance of Overhead Lines	146,409	2,456						
43			594.0 Maintenance of Underground Lines	36,176	916						
44			595.0 Maintenance of Line Transformers	2,061	23						
45			596.0 Maintenance of Street Lighting & Signal Systems	1,539	5						
46			598.0 Maintenance of Misc. Distribution	17,980	219						
47			Sub-total Distribution Maintenance	$226,712	$4,119						
48											

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Category	Description	Account	HTY Amount Pre Adjustments	D-5D Energy Efficiency Program Expense	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 IIJA Reg Asset
49			Sub-total DISTRIBUTION EXPENSE	$356,034		$5,244					
50											
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision								
52			902.0 Meter Reading	$622		0					
53			903.0 Customer Records and Collection	94,383		1,661					
54			904.0 Uncollectible Accounts	42,082						5,083	
55			905.0 Miscellaneous Customer Accounts Expenses.	3,726		35					
56			Sub-total Customer Accounts	$140,812		$1,696				$5,083	
57											
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance	$92,332	($78,630)	$75					
59			909.0 Informational & Instructional	897							
60			910.0 Miscellaneous Customer & Informational	738		10					
61			Sub-total Customer Service & Information	$93,967	($78,630)	$85					
62											
63	**SALES**	**Sales**	912.0 Demonstrating & Selling	$318		$10					
64			916.0 Miscellaneous Sales								
65			Sub-total Sales	$318		$10					
66											
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries	$24,463		$1,139					
68			921.0 Office Supplies and Expenses	5,018							
69			922.0 Administrative Expenses Transferred-Credit								
70			923.0 Outside Service Employed	86,778							
71			924.0 Property Insurance	761							
72			925.0 Injuries & Damages	17,372		82					
73			926.0 Employee Pensions and Benefits	15,665		2		500	11,829		
74			928.0 Regulatory Commission Expenses	7,712			1,200				
75			929.0 Duplicate Charges-Credit	(1,343)							
76			930.2 Miscellaneous General Expenses	2,295		2					
77			Sub-total A&G Operations	$158,722		$1,225	$1,200	$500	$11,829		
78											
79		A&G Maintenance	935.0 Maintenance of General Plant	$6,019		$63					
80											
81			Sub-total ADMINISTRATION & GENERAL	$164,741		$1,288	$1,200	$500	$11,829		
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$216,304							
84			404.0 Amort. Of Limited-Term Electric Plant.	41,838							
85			Sub-total Depreciation & Amortization Expense	$258,142							
86											
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.								($448)
88			Sub-total Amortization of Regulatory Expense								($448)
89											
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$189,450							
91			Sub-total Taxes Other Than Income Taxes - Other	$189,450							
92											
93			**Total**	**$2,474,003**	**($78,630)**	**$8,323**	**$1,200**	**$500**	**$11,829**	**$5,083**	**($448)**

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 Storm	D-14 Other Adjustments	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.								$1,073,543
2			Sub-total Power Supply								$1,073,543
3											
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision								
5			561.0 Load Dispatching								
6			561.4 Scheduling, System Control & Dispatch								99,062
7			561.6 Transmission Service Studies								
8			561.7 Generation Service Studies								
9			561.8 Reliability, Planning & Standard Development								97,936
10			562.0 Station Expense								
11			563.0 Overhead Lines								
12			564.0 Underground Lines Expense								
13			566.0 Miscellaneous Expense								
14			567.0 Rents								
15			Sub-total Transmission Operations								196,997
16											
17		**Transmission Maintenance**	569.0 Maintenance of Structures								
18			569.1 Maintenance of Computer Hardware								
19			569.2 Maintenance of Computer Software								
20			569.3 Maintenance of Communication Equipment								
21			570.0 Maintenance of Station Equipment								
22			571.0 Maintenance of Overhead Lines								
23			572.0 Maintenance of Underground Lines								
24			573.0 Maintenance of Misc Transmission Plant								
25			Sub-total Transmission Maintenance								
26											
27			Sub-total TRANSMISSION EXPENSE								196,997
28											
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision							$48	$1,279
30			581.0 Load Dispatching								
31			582.0 Station Expense							$2	$680
32			583.0 Overhead Lines Expenses							$178	$14,736
33			584.0 Underground Lines Expense							$130	$11,098
34			586.0 Meter Expenses							$125	$6,620
35			587.0 Customer Installations Expense							$300	$12,758
36			588.0 Miscellaneous Expense							$341	$79,740
37			589.0 Rents								$3,535
38			Sub-total Distribution Operations							$1,125	$130,446
39											
40		**Distribution Maintenance**	591.0 Maintenance of Structures							$61	$5,002
41			592.0 Maintenance of Station Equipment							440	18,046
42			593.0 Maintenance of Overhead Lines		27,972					30,428	176,837
43			594.0 Maintenance of Underground Lines							916	37,092
44			595.0 Maintenance of Line Transformers							23	2,084
45			596.0 Maintenance of Street Lighting & Signal Systems							5	1,544
46			598.0 Maintenance of Misc. Distribution							219	18,198
47			Sub-total Distribution Maintenance		$27,972					$32,092	$258,804
48											

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 Storm	D-14 Other Adjustments	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
49			Sub-total DISTRIBUTION EXPENSE		$27,972					$33,216	$389,250
50											
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision								
52			902.0 Meter Reading							$0	$622
53			903.0 Customer Records and Collection							$1,661	96,044
54			904.0 Uncollectible Accounts							5,083	47,164
55			905.0 Miscellaneous Customer Accounts Expenses.	3,572		(43)				3,564	7,290
56			Sub-total Customer Accounts	$3,572		($43)				$10,308	$151,121
57											
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance							($78,555)	$13,777
59			909.0 Informational & Instructional								897
60			910.0 Miscellaneous Customer & Informational							10	748
61			Sub-total Customer Service & Information							($78,545)	$15,422
62											
63	**SALES**	**Sales**	912.0 Demonstrating & Selling							$10	$328
64			916.0 Miscellaneous Sales								
65			Sub-total Sales							$10	$328
66											
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries							$1,139	$25,603
68			921.0 Office Supplies and Expenses								5,018
69			922.0 Administrative Expenses Transferred-Credit								
70			923.0 Outside Service Employed								86,778
71			924.0 Property Insurance								761
72			925.0 Injuries & Damages							82	17,454
73			926.0 Employee Pensions and Benefits							12,331	27,996
74			928.0 Regulatory Commission Expenses							1,200	8,912
75			929.0 Duplicate Charges-Credit								(1,343)
76			930.2 Miscellaneous General Expenses			1,000				1,002	3,298
77			Sub-total A&G Operations			$1,000				$15,754	$174,477
78											
79		A&G Maintenance	935.0 Maintenance of General Plant							$63	$6,082
80											
81			Sub-total ADMINISTRATION & GENERAL			$1,000				$15,818	$180,559
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$10,397	$10,397	$226,701
84			404.0 Amort. Of Limited-Term Electric Plant.						3,562	3,562	45,400
85			Sub-total Depreciation & Amortization Expense						$13,959	$13,959	$272,101
86											
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.							($448)	($448)
88			Sub-total Amortization of Regulatory Expense							($448)	($448)
89											
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					$3,370		$3,370	$192,819
91			Sub-total Taxes Other Than Income Taxes - Other					$3,370		$3,370	$192,819
92											
93			**Total**	**$3,572**	**$27,972**	**$957**		**$3,370**	**$13,959**	**($2,312)**	**$2,471,691**

Line No.	Category	Category	Description	Account	(1) HTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act - 129 Lost Revenue Due To Load Reduction	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E OPEN	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization	(9) Adjustments Sub-total	(10) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	440.0	$875,808	$2,121	$3,155	($2,067)	($25,681)		$433	$38,076	$16,036	$891,844
2			Residential - House Heating	440.1	156,268	1,713	427	(432)	(6,066)		105	18,701	14,447	170,715
3			C & I Small	442.0	292,195	598		(1,561)	(32,719)		141	8,582	(24,960)	267,235
4			C & I Large	442.1	190,530	575		(858)	(17,249)		123	2,467	(14,942)	175,589
5			Railroads & Railways	446.0	8,117				(563)				(563)	7,554
6			Street Lighting	444.0	21,011				(584)				(584)	20,427
7			Intercompany	448.0	166									166
8			Transmission - All Classes		209,772									209,772
9			Sub-total - Customer & Distribution Revenues		$1,753,867	$5,007	$3,583	($4,919)	($82,863)		$803	$67,825	($10,565)	$1,743,302
10														
11		**Electric Cost Revenue**	Residential	440.0	$745,840									$745,840
12			Residential - House Heating	440.1	176,253									176,253
13			C & I Small	442.0	193,399									193,399
14			C & I Large	442.1	24,714									24,714
15			Railroads & Railways	446.0										
16			Street Lighting	444.0	1,069									1,069
17			Intercompany	448.0										
18			Sub-total - Electric Cost Revenue		$1,141,275									$1,141,275
19														
20			**Total OPERATING REVENUE**		$2,895,142	$5,007	$3,583	($4,919)	($82,863)		$803	$67,825	($10,565)	$2,884,577
21														
22	*OTHER REVENUE*	**Other Electric Revenue**	Rent For Electric Property	454.0	$21,995									$21,995
23			Other Electric Revenues	456.0	6,833									6,833
24			Transmission of Electricity for Others	456.1										
25			Sub-total - Other electric Revenue		$28,828									$28,828
26														
27		**Other Operating Revenue**	Forfeited Discounts	450.0	$16,337									$16,337
28			Miscellaneous Service Revenues	451.0	4,933									4,933
29			Sub-total - Other Operating Revenue		$21,270									$21,270
30														
31			**Total OTHER REVENUE**		$50,097									$50,097
32														
33			**Total REVENUE**		**$2,945,240**	**$5,007**	**$3,583**	**($4,919)**	**($82,863)**		**$803**	**$67,825**	**($10,565)**	**$2,934,674**

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Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales	(3) 442001: C&I Sales-Small	(4) 442002: C&I Sales-Large	(5) C & I Total
1	Total HTY Revenues		$1,731,923	$358,237	$527,054	$248,056	$775,110
2	Commodity Billings in Revenues		(856,115)	(201,969)	(234,859)	(57,526)	(292,385)
3	Weather Adjustment		38,076	18,701	8,582	2,467	11,049
4	Total Reconcilable Surcharge in Revenues		(19,546)	(4,615)	(28,299)	(9,066)	(37,365)
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$894,338	$170,353	$272,478	$183,931	$456,409
6							
7	Average Monthly Customers in HTY		1,330,590	200,169	155,906	3,117	159,023
8							
9	Average Annual Margin Per Customer	L5 / L7	$0.672	$0.851	$1.748	$59.004	$2.870
10							
11	Number of Customers at end of HTY		1,333,745	202,182	156,248	3,127	159,375
12							
13	Increase in Customers during HTY	L11 - L7	3,155	2,013	342	10	352
14							
15	**Annualization of Revenue**	L9 * L13	**$2,121**	**$1,713**	**$598**	**$575**	**$1,173**

		(1)	(2)	(3)
Line No.	Description	Reference	440000: Residental Sales	440001: Residental Heating Sales
1	CAP Discount		($123,885)	($16,782)
2				
3				
4	**ANNUALIZATION TO YEAR END CUSTOMERS**			
5				
6	Annual CAP Customers		1,355,844	163,920
7	Average Monthly CAP Customers		112,987	13,660
8	Average Annual CAP Discount Per Customer	L1 / L7	($1.096)	($1.229)
9				
10	CAP Customers at End of HTY		109,772	13,271
11	Increase of CAP Customers	L10 - L7	(3,215)	(389)
12				
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	$3,525	$478
14	Write-Offs & Working Capital Factor		10.5%	10.5%
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	($370)	($50)
16				
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**$3,155**	**$427**

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	(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	2024 Revenue Loss	2025 Revenue Loss	2026 Revenue Loss Over 2025	Recovery of Incremental Revenue Loss
1	**Revenue Impact in 2024 - Included in HTY Year Budget**					
2	Residential		($4,912)			
3	Residential Heaing		($1,027)			
4	Small C&I		($4,154)			
5	Large C&I		($1,091)			
6	Total	SUM L2 to L5	($11,185)			
7						
8	**Target Revenue Impact in 2024**					
9	Residential			($9,047)		
10	Residential Heaing			($1,892)		
11	Small C&I			($7,277)		
12	Large C&I			($2,808)		
13	Total	SUM L9 to L12		($21,023)		
14						
15	**Incremental Revenue Impact Over HTY Budget**					
16	Residential	L9 - L2			($4,135)	
17	Residential Heaing	L10 - L3			(865)	
18	Small C&I	L11 - L4			(3,123)	
19	Large C&I	L12 - L5			(1,716)	
20	Total	SUM L16 to L19			($9,839)	
21						
22	**Average Annual Incremental Revenue Not in HTY Budget**					
23	Residential	L16 / 2				($2,067)
24	Residential Heaing	L17 / 2				(432)
25	Small C&I	L18 / 2				(1,561)
26	Large C&I	L19 / 2				(858)
27	**Total**	SUM L23 to L26				**($4,919)**

Line No.	Account / Description	(1) Reference	(2) Total
1	440000: Residential Sales		($25,681)
2	440001: Residential Heating Sales		(6,066)
3	442001: C&I Sales-Small		(32,719)
4	442002: C&I Sales-Large		(17,249)
5	444000: Public Street/Highway Lighting		(584)
6	446000: Sales-Railroad/Railway		(563)
7	**Reduction in Retail Revenue**	SUM L1 to L6	**($82,863)**
8			
9	O&M Expense		($78,630)

		(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Reference	440000: Residental Sales	440001: Residental Heating Sales	442001: C&I Sales-Small	442002: C&I Sales-Large	C & I Total
1	Revenue in February of HTY		$48,533	$11,758	$15,777	$13,812	$29,589
2	Days in February of HTY		28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	$1,733	$420	$563	$493	
4	Average Days in February		28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	
6							
7	**Leap Year Adjustment**	L3 * L5	**$433**	**$105**	**$141**	**$123**	**$264**

(1)

Line No.	Account	Total
1	Residental Sales	$38,076
2	Residental Heating Sales	18,701
3	C&I Sales-Small	8,582
4	C&I Sales-Large	2,467
5		
6	**Total**	**$67,825**

Line No.	Description	Reference	(1) Union	(2) Non-Union
1	Number of Employees @ HTY - Union/Non-Union		1,044	1,168
2	Number of Employees @ HTY - Total		2,213	2,213
3	Percentage of Employees @ HTY	L1 / L2	47.20%	52.80%
4	Distribution of Budget S&W Expense		$70,415	$78,756
5				
6	**Annualize March 1 Wage Increase for HTY**			
7	Number of Months TY			2
8	Rate for Increase TY		2.50%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$394
10		L4 + L9	$70,415	$79,150
11				
12	**Annualize January 1 and March 1, 2024 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		2.50%	3.00%
15	Total Adjustment	(L10 * L13) / 12	$1,760	$2,374
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$72,175**	**$81,524**

		(1)	(2)
Line No.	Description	Reference	Amount
1	Distribution of S&W Expense		$149,170
2			
3	Annualized S&W Including Wage Increases		$153,699
4			
5	**Adjustment for Union Contract**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		77.49%
8	Union Contract Payment for Utility	L6 * L7	$1,010
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$168
11			
12	Adjusted S&W for Employees in HTY	L3 + L10	$153,867
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ HTY		2,213
16	Average Number of Employees in HTY - Total		2,162
17	Annualization for Number of Employees	L15 - L16	51
18	Annual S&W per Employee	L12 / L16	$71.2
19	Annualization of S&W for New Employees	L17 * L18	$3,626
20			
21	Pro Forma HTY S&W	L12 + L19	$157,493
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$8,323**
24			
25	S&W Pro Forma Factor	L23 / L1	5.58%

				(1)	(2)	(3)
Line No.	Category	Description	Account	Jurisdictional Payroll Amount	Pro Forma Payroll Adjustment	Total Adjusted Payroll
1	**Operations**	**Power Supply Expenses**	555.0 Purchased Power.			
2			Sub-total Power Supply Expenses			
3						
4		**Transmission Expense**	560.0 Operation & Supervision			
5			561.0 Load Dispatching			
6			561.4 Scheduling, System Control & Dispatch			
7			561.6 Transmission Service Studies			
8			561.7 Generation Service Studies			
9			561.8 Reliability, Planning & Standard Development			
10			562.0 Station Expense			
11			563.0 Overhead Lines			
12			564.0 Underground Lines Expense			
13			566.0 Miscellaneous Expense			
14			567.0 Rents			
15			569.0 Maintenance of Structures			
16			569.1 Maintenance of Computer Hardware			
17			569.2 Maintenance of Computer Software			
18			569.3 Maintenance of Communication Equipment			
19			570.0 Maintenance of Station Equipment			
20			571.0 Maintenance of Overhead Lines			
21			572.0 Maintenance of Underground Lines			
22			573.0 Maintenance of Misc Transmission Plant			
23			Sub-total Transmission Expense			
24						
25		**Distribution Expense**	580.0 Operation & Supervision	$854	$48	$901
26			581.0 Load Dispatching			
27			582.0 Station Expense	44	2	46
28			583.0 Overhead Lines Expenses	3,199	178	3,377
29			584.0 Underground Lines Expense	2,336	130	2,466
30			586.0 Meter Expenses	2,232	125	2,357
31			587.0 Customer Installations Expense	5,385	300	5,685
32			588.0 Miscellaneous Expense	6,107	341	6,448
33			589.0 Rents			
34			591.0 Maintenance of Structures	1,084	61	1,145
35			592.0 Maintenance of Station Equipment	7,878	440	8,317
36			593.0 Maintenance of Overhead Lines	44,019	2,456	46,475
37			594.0 Maintenance of Underground Lines	16,420	916	17,336
38			595.0 Maintenance of Line Transformers	417	23	441
39			596.0 Maintenance of Street Lighting & Signal Systems	92	5	97
40			598.0 Maintenance of Misc. Distribution	3,919	219	4,138
41			Sub-total Distribution Operations	$93,987	$5,244	$99,231
42						

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
43	**Customer Accounts**		901.0 Supervision			
44			902.0 Meter Reading	0	$0	0
45			903.0 Customer Records and Collection	$29,773	$1,661	$31,434
46			904.0 Uncollectible Accounts.			
47			905.0 Miscellaneous Customer Accounts Expenses.	623	35	658
48			Sub-total Customer Accounts	$30,396	$1,696	$32,092
49						
50	**Customer Service & Information**		908.0 Customer Assistance	$1,349	$75	$1,424
51			909.0 Informational & Instructional			
52			910.0 Miscellaneous Customer & Informational	172	10	182
53			Sub-total Customer Service & Information	$1,521	$85	$1,606
54						
55	**Sales**		912.0 Demonstrating & Selling	$180	$10	$190
56			916.0 Miscellaneous Sales			
57			Sub-total Sales	$180	$10	$190
58						
59	**Administration & General**		920.0 Administrative and General Salaries	$20,422	$1,139	$21,561
60			921.0 Office Supplies and Expenses			
61			922.0 Administrative Expenses Transferred-Credit			
62			923.0 Outside Service Employed			
63			924.0 Property Insurance			
64			925.0 Injuries & Damages	1,462	82	1,544
65			926.0 Employee Pensions and Benefits	27	2	29
66			928.0 Regulatory Commission Expenses			
67			929.0 Duplicate Charges-Credit			
68			930.2 Miscellaneous General Expenses	43	2	45
69			935.0 Maintenance of General Plant	1,132	63	1,195
70			Sub-total Administration & General	$23,087	$1,288	$24,375
71						
72			**Total**	**$149,170**	**$8,323**	**$157,493**
73						
74			**Percent Increase**			5.58%

Line No.	Description	(1) Reference	(2) Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$3
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		$6
4	Total Recorded Up To Period End of HTY	SUM L2 to L3	$9
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$1,997
8	Materials, IT Costs, Travel, Copies, etc.		394
9	Total Expenditure Expected in FTY	SUM L7 to L8	$2,391
10			
11	Total Rate Case Expense	L4 + L9	$2,400
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,200
15			
16	Annual Amortization Amount Included in Budget		
17	**Pro Forma Adjustment for Annual Amortization**	L14 - L16	**$1,200**

Line No.	Description	Reference	(1) Jurisdictional Amount
1	**Number of Employees**		
2	Employees at Eleven Months Prior		2,103
3	Employees at Ten Months Prior		2,108
4	Employees at Nine Months Prior		2,129
5	Employees at Eight Months Prior		2,137
6	Employees at Seven Months Prior		2,137
7	Employees at Six Months Prior		2,141
8	Employees at Five Months Prior		2,145
9	Employees at Four Months Prior		2,165
10	Employees at Three Months Prior		2,229
11	Employees at Two Months Prior		2,218
12	Employees at One Month Prior		2,215
13	Employees at End of FTY		2,213
14			
15	Average Monthly Employees in HTY	AVERAGE L2 to L13	2,162
16	Additional Employees in HTY		51
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$21,215
20	Number of Employees for Budget		2,162
21	Budget Expense Per Employee	L19 / L20	$10
22	Additional Employees for Annualization	L16	51
23	**Total Benefits Pro Forma Adjustment**	L21 * L22	**$500**

Line No.	Description	Reference	Total - PECO
		(1)	(2)
1	Pension Contribution for Four Years Prior to HTY		$26,339
2	Pension Contribution for Three Years Prior to HTY		18,006
3	Pension Contribution for Two Years Prior to HTY		17,267
4	Pension Contribution for One Year Prior to HTY		15,222
5	Pension Contribution for HTY		1,408
6			
7	Average Pension Contribution	Average L1 to L5	$15,648
8			
9	Percent to Electric Distribution		77.49%
10	Total Amount to Electric Distribution	L7 * L9	$12,125
11	Pension Capitalization Factor		48.21%
12	Pension Contribution To Be Capitalized	L10 * L11	5,846
13	Pension Contribution To Be Expensed	L10 - L12	$6,279
14	FPFTY Distribution Pension Expense		(5,550)
15	**Additional Pension Expense**	L13 - L14	**$11,829**

Line No.	Description	Reference	Reference	Charge Off Amounts	InPA Charge Off Amounts	Net Charge Off Amounts	Billed Revenue	Percent	PPA	Totals
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$29,237	$2,395	$26,842	$3,365,014	0.7977%		
2		One Year Prior to HTY		37,820	(28)	37,848	3,810,090	0.9934%		
3		HTY		42,650	17	42,632	3,880,008	1.0988%		
4		Three Year Average	SUM L1 to L3 / 3	$36,569	$795	$35,774	$3,685,037	0.9708%		
5										
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	HTY					$2,884,577			
7										
8	Tariff Revenue - Non Shopping Revenue	HTY	L6				$2,884,577			
9										
10	Tariff Revenue - Shopping Revenue	HTY					1,016,077			
11										
12	Tariff Revenue - Including Shopping Revenue	HTY	L8 + L10				$3,900,654			
13										
14	**Total General Pro Forma Uncollectible Accounts**		Col 7 L4 * L12							$37,867
15										
16	**NET PPA UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY						$6,462		
17		One Year Prior to HTY						9,314		
18		HTY						12,116		
19										
20	**Three Year Average PPA**		SUM L16 to L18 / 3							$9,297
21										
22	**Total Pro Forma Uncollectible Accounts**		L14 + L20							$47,164
23										
24	Uncollectible Accounts (904)	HTY								$42,082
25										
26	**Total Pro Forma Adjustment for Uncollectible Accounts**		L22 - L24							**$5,083**

		(1)	(2)
Line No.	Description	Reference	Total
1	Actual IIJA Related Incremental Costs in 2022 and 2023		$411
2	Amortization Years		2
3	Pro Forma Adjustment Amount	L1 / L2	$205
4	Remove Estimated IIJA Related Incremental Costs in 2025		(653)
5	Total Pro Forma Adjustment Amount	L3 + L4	($448)

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			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Description	Reference	Interest Rate	Deposit Amount	Interest on Deposit Amount	Interest Sub Total	Interest Total
1	**Residential**	Monthly Interest Rate		0.667%				
2								
3	January				18,976	127		
4	February				19,166	128		
5	March				19,446	130		
6	April				20,077	134		
7	May				20,877	139		
8	June				21,538	144		
9	July				22,060	147		
10	August				22,549	150		
11	September				22,772	152		
12	October				23,058	154		
13	November				23,276	155		
14	December				23,215	155		
15	**Total Residential**		SUM Col 4 L3 to L14				$1,713	
16								
17	**Non-Residential**	Monthly Interest Rate		0.425%				
18								
19	January				32,487	138		
20	February				33,197	141		
21	March				33,844	144		
22	April				34,307	146		
23	May				35,117	149		
24	June				35,642	151		
25	July				36,988	157		
26	August				38,022	162		
27	September				38,782	165		
28	October				39,358	167		
29	November				39,646	168		
30	December				39,988	170		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$1,859	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					**$3,572**

		(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Reference	Tri- State CPI Factor	Inflation Factor	Expense In Year	Amount for Average	Total
1	4/1/2019 - 3/31/2020		-	1.22448	$32,500	$39,796	
2	4/1/2020 - 3/31/2021		0.00696	1.22448	$118,822	$145,495	
3	4/1/2021 - 3/31/2022		0.05645	1.21602	$56,495	$68,699	
4	4/1/2022 - 3/31/2023		0.07555	1.15105	$17,144	$19,734	
5	4/1/2023 - 3/31/2024		0.03888	1.07019	$67,284	$72,006	
7							
8	Average Storm Restoration Expense at 2025 cost levels	AVERAGE L1 to L5					$69,146
9							
10	HTY Budget						$41,173
11							
12	**Pro Forma Adjustment for Storm Expense Normalization**	L9 - L11					**$27,972**

Line No.	Description	(1) Reference	(2) Total
1	Final Tax Accounting Repair Credit (TARC) - Electric		
2	Residential		(36)
3	Small C&I		(14)
4	Large C&I		(9)
5	Street Lighting		(3)
6	Sub-total TARC Credit	SUM L2 to L5	($62)
7	Final Federal Tax Adjustment Credit (FTAC) - Electric		
8	Residential		($37)
9	Small C&I		(1)
10	Street Lighting		(0)
11	Large C&I & Railroads		15
12	Sub-total FTAC Credit	SUM L8 to L11	($23)
13	Total TARC and FTAC Credit	L6 + L12	($86)
14	Amortization Years		2
15	Pro Forma Adjustment Amount	L13 / L14	($43)
16			
17	EV Incentive Rebates		1,000

Line No.	Description	Transmission Percentage / Reference	Total Electric	Transmission Elimination	Distribution	Pro Forma Adjustments	Pro Forma Tax Expense
		(1)	(2)	(3)	(4)	(5)	(6)
1	Public Utility Real Tax (PURTA) Total Expense	17.825%	$6,819	($1,216)	$5,604		$5,604
2	Use Tax Accrued	17.825%	2,345	(418)	1,927		1,927
3	Real Estate Tax Accrued	17.825%	5,664	(1,010)	4,655		4,655
4	Miscellaneous TOTI	12.373%	46	(6)	41		41
5	Payroll Tax Accrued	12.373%	13,211	(1,635)	11,576	646	12,222
6	Sub-total TOTI - Other	SUM L1 to L5	$28,086	($4,284)	$23,802	$646	$24,448
7							
8	Gross Receipt Tax		$165,647		$165,647	$2,724	$168,371
9							
10	**Total**	L6 + L8	**$193,733**	**($4,284)**	**$189,450**	**$3,370**	**$192,819**

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Line No.	Description	(1) Reference	(2) Jurisdictional
1	Total Payroll Charged to Expense		$149,170
2	Payroll Tax Expense		$11,576
3	Payroll Tax Expense - Percent	L2 / L1	7.76%
4	Pro Forma Increase in S&W		$8,323
5	**Payroll Tax Pro Forma**	L3 * L4	**$646**

Line No.	Description	Reference	(1) Total
1	**GROSS RECEIPTS TAX PRO FORMA AT PRESENT RATE**		(2)
2			
3	Residential		$1,637,684
4	Residential Heating		346,968
5	Small C&I		460,634
6	Large C&I		200,302
7	Railroads & Railways		7,554
8	Street Lighting & Highway		21,496
9	Interdepartmental Sales - Electric		166
10	Transmission		209,772
11	Sub-total	SUM L3 to L10	$2,884,577
12			
13	Forfeited Discounts - Electric		$16,337
14	Uncollectible Accounts		(47,164)
15	COVID-19 Related Incremental Bad Debt Expense		
16	Sub-total	SUM L13 to L15	($30,828)
17			
18	Total HTY at Present Rates	L11 + L16	$2,853,749
19			
20	Gross Receipts Tax Rate		5.90%
21			
22	Pro Forma Gross Receipts Expense at Present Rates	L18 * L20	$168,371
23			
24	HTY Budget		$165,647
25			
26	**Net Adjustment**	L22 - L24	**$2,724**

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Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	$1,229	$216	$1,012	$216	$1,445
2			PECO Elec 3650 PA LTIIP	2,240	180	2,060	180	2,420
3			PECO Elec 3660 PA LTIIP	1,473	423	1,050	423	1,896
4			PECO Elec 3670 PA LTIIP	2,723	507	2,216	507	3,230
5			PECO Elec 3705 SM UD RES PA	10,189		10,189		10,189
6			PECO Elec 3706 Non DOE Rcv PA	2,351		2,351		2,351
7			PECO Elec 3707 SM RES PA	5,352	297	5,054	297	5,649
8			PECO Elec 3708 SM SCI PA	863	8	855	8	871
9			PECO Elec 3709 SM LCI PA	1,132	56	1,076	56	1,189
10			PECO Elec Dist-ARC EXP PA	(3)		(3)		(3)
11			PECO Electric 3611 PA	1,257	267	990	267	1,524
12			PECO Electric 3612 PA	2,553	115	2,438	115	2,668
13			PECO Electric 3613 PA	206	1	205	1	207
14			PECO Electric 3620 PA	21,678	233	21,445	233	21,911
15			PECO Electric 3640 PA	22,749	1,320	21,429	1,320	24,069
16			PECO Electric 3650 PA	36,963	1,972	34,991	1,972	38,935
17			PECO Electric 3660 PA	8,764	297	8,467	297	9,062
18			PECO Electric 3670 PA	32,674	1,318	31,356	1,318	33,992
19			PECO Electric 3680 PA	16,583	1,096	15,487	1,096	17,679
20			PECO Electric 3691 PA	3,453	114	3,339	114	3,568
21			PECO Electric 3692 PA	4,919	32	4,887	32	4,950
22			PECO Electric 3701 PA	145	7	138	7	152
23			PECO Electric 3710 PA	4		4		4
24			PECO Electric 3730 PA	884	7	877	7	892
25			PECO Electric 3731 PA	76	0	76	0	76
26			PECO Electric 3732 PA	925	(26)	951	(26)	900
27			PECO Electric 3733 PA	36		36		36
28			Sub-total Electric - Distribution	$181,419	$8,442	$172,977	$8,442	$189,862
29			Sub-total Electric - Distribution	$181,419	$8,442	$172,977	$8,442	$189,862
30								
31		Common - General Plant	PECO Common 3901 PA	$4,133	($16)	$4,149	($16)	$4,117
32			PECO Common 3902 IL	17		17		17
33			PECO Common 3902 PA	2,453	289	2,164	289	2,742
34			PECO Common 3903 PA	57	5	52	5	62
35			PECO Common 3911 PA	13		13		13
36			PECO Common 3912 PA	2,125	102	2,023	102	2,228
37			PECO Common 3913 IL	1,056	65	991	65	1,120
38			PECO Common 3913 PA	7,239	1,461	5,778	1,461	8,700
39			PECO Common 3930 PA	104	9	95	9	113
40			PECO Common 3941 PA	2		2		2
41			PECO Common 3942 PA	66		66		66
42			PECO Common 3970 PA	5,691	139	5,552	139	5,830

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
43			PECO Common 3980 PA	84		84		84
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	18		18		18
45			PECO Elec 3919 SM Comp Equip IL	36		36		36
46			PECO Elec 3919 SM Comp Equip MD	13		13		13
47			PECO Elec 3919 SM Comp Equip NC	7		7		7
48			PECO Elec 3919 SM Comp Equip PA	11		11		11
49			PECO Elec 3949 SM Tools PA	7		7		7
50			PECO Elec 3979 SM Comm Equip PA	2,649	9	2,640	9	2,658
51			PECO Electric 3901 PA	802	9	793	9	810
52			PECO Electric 3902 PA	393	2	391	2	395
53			PECO Electric 3903 PA	5	4	1	4	8
54			PECO Electric 3911 PA	1		1		1
55			PECO Electric 3912 PA	64	5	59	5	69
56			PECO Electric 3913 PA	6,894	273	6,621	273	7,166
57			PECO Electric 3930 PA	4		4		4
58			PECO Electric 3940 PA	3,475	225	3,250	225	3,700
59			PECO Electric 3951 PA	13		13		13
60			PECO Electric 3952 PA	1		1		1
61			PECO Electric 3970 PA	7,628	122	7,505	122	7,750
62			PECO Electric 3980 PA	61	2	59	2	63
63			Sub-total Electric - General Plant	$45,122	$2,705	$42,418	$2,705	$47,827
64			Sub-total Electric - General Plant	$45,122	$2,705	$42,418	$2,705	$47,827
65								
66		Electric - Transmission	PECO Electric 3521 PA	$402	($3)	$406	($3)	$399
67			PECO Electric 3522 MD	1		1		1
68			PECO Electric 3522 NJ	0		0		0
69			PECO Electric 3522 PA	1,458	19	1,439	19	1,477
70			PECO Electric 3523 NJ	0		0		0
71			PECO Electric 3523 PA	49	1	48	1	49
72			PECO Electric 3530 NJ	66		66		66
73			PECO Electric 3530 PA	17,720	203	17,518	203	17,923
74			PECO Electric 3540 DE	92		92		92
75			PECO Electric 3540 MD	52		52		52
76			PECO Electric 3540 NJ	217		217		217
77			PECO Electric 3540 PA	3,098	1	3,097	1	3,099
78			PECO Electric 3550 PA	421	19	402	19	440
79			PECO Electric 3560 DE	5		5		5
80			PECO Electric 3560 MD	12		12		12
81			PECO Electric 3560 NJ	127	37	90	37	164
82			PECO Electric 3560 PA	4,079	99	3,980	99	4,179
83			PECO Electric 3570 PA	633	379	253	379	1,012
84			PECO Electric 3580 PA	2,079	414	1,665	414	2,493

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
85			PECO Electric 3590 NJ	4		4		4
86			PECO Electric 3590 PA	24	(6)	30	(6)	19
87			Sub-total Electric - Transmission	$30,540	$1,163	$29,377	$1,163	$31,703
88								
89			Sub-total 403.0 Depreciation Expense	$257,081	$12,310	$244,772	$12,310	$269,391
90			Sub-total Electric - Transmission	$30,540	$1,163	$29,377	$1,163	$31,703
91								
97	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 3030- North Star RE SW	$447		$447		$447
98			PECO Com 3030-Apollo SW	685	685		685	1,369
99			PECO Com 3030-BIDA Customer Project	1,849		1,849		1,849
100			PECO Com 3030-BIDA-AMI Ph2 SW	2,139		2,139		2,139
101			PECO Com 3030-CIS Transformation SW	204		204		204
102			PECO Com 3030-Cloud Serv 3 yr	1,962	1,073	889	1,073	3,035
103			PECO Com 3030-Cloud Serv 5 yr	2,780	1,357	1,423	1,357	4,138
104			PECO Com 3030-Common MDM SW	8,309	219	8,090	219	8,528
105			PECO Com 3030-CTA PHI Consol SW	19		19		19
106			PECO Com 3030-Cust Appt Sched SW	615		615		615
107			PECO Com 3030-Digital Strat Platfor	123		123		123
108			PECO Com 3030-EU Dig Strat EPay SW	444		444		444
109			PECO Com 3030-EU Digital Program We	1,657	863	793	863	2,520
110			PECO Com 3030-EU oneMDS SW	2,759	2,759		2,759	5,518
111			PECO Com 3030-Fusion Mig Non-MDM SW	791		791		791
112			PECO Com 3030-I Sign Up and Move	1,568		1,568		1,568
113			PECO Com 3030-IT Cust Mobile App SW	102	67	35	67	169
114			PECO Com 3030-IVR System PA	127	98	29	98	226
115			PECO Com 3030-Lease IT SW	112		112		112
116			PECO Com 3030-Misc 5 yr FR PA	6,784	(2,595)	9,379	(2,595)	4,189
117			PECO Com 3030-Misc 5 yr PA	12	12		12	25
118			PECO Com 3030-Mobile Dispatch Mappi	5,842		5,842		5,842
119			PECO Com 3030-OBIEE Migration SW	1,099		1,099		1,099
120			PECO Com 3030-Oracle MW Upgrade SW	261		261		261
121			PECO Com 3030-Rev Req Filing SW	390		390		390
122			PECO Com 3030-Robotic Process Auto	89		89		89
123			PECO Com 3030-SCP Splunk SW	2		2		2
124			PECO Elec 303 Elec Configuration SW	551		551		551
125			PECO Elec 303 EV-FC	70		70		70
126			PECO Elec 303 NERC CIP Systems D PA	2		2		2
127			PECO Elec 303 NERC CIP Systems PA	17		17		17
128			PECO Elec 303 SLC	111		111		111
129			PECO Elec 303 SM AMOS PA	379		379		379
130			PECO Elec 303-BIDA Grid T&D Domain	1,762		1,762		1,762
131			PECO Elec 303-CFP - Outage SW D	86	86		86	172

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
132			PECO Elec 303-CFP - Outage SW T	15	15		15	30
133			PECO Elec 303-Dist Auto Ntwk Upg Hi	763		763		763
134			PECO Elec 303-EMS Implementation Pr	3,321		3,321		3,321
135			PECO Elec 303-EU Custom Analytics S	278		278		278
136			PECO Elec 303-EU Digital Solar Tool	327		327		327
137			PECO Elec 303-EU Load Forecast SW	723		723		723
138			PECO Elec 303-EU Ratings DB SW D	12		12		12
139			PECO Elec 303-EU Ratings DB SW T	155		155		155
140			PECO Elec 303-EU TOA Implementation	995		995		995
141			PECO Elec 303-PECO RNI Upgrade SW D	1,380		1,380		1,380
142			PECO Elec 303-PECO TOU SW	1,370		1,370		1,370
143			PECO Elec 303-SES IV D SW	2,364		2,364		2,364
144			PECO Elec 3030 - BIDA Smart Energy A (Original)	459		459		459
145			PECO Elec 3030-Cloud Serv 3 yr	254		254		254
146			PECO Elec 3030-Cloud Serv 5 yr	443	91	352	91	534
147			PECO Electric 303 Misc 5 FR PA	3,484	384	3,099	384	3,868
148			Sub-total Electric - Intangible Plant	$60,494	$5,115	$55,380	$5,115	$65,609
149								
150			Sub-total 404.0 Amort. of Limited-Term Electric Plant	$60,494	$5,115	$55,380	$5,115	$65,609
151								
152			**Total**	$317,576	$17,424	$300,151	$17,424	$335,000
153			Sub-total Electric - Intangible Plant	$60,494	$5,115	$55,380	$5,115	$65,609
154								
155			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.	$60,494	$5,115	$55,380	$5,115	$65,609

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Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$1,229	$216	$1,012	$216	$1,445
2			PECO Elec 3650 PA LTIIP	1.0000	2,240	180	2,060	180	2,420
3			PECO Elec 3660 PA LTIIP	1.0000	1,473	423	1,050	423	1,896
4			PECO Elec 3670 PA LTIIP	1.0000	2,723	507	2,216	507	3,230
5			PECO Elec 3705 SM UD RES PA	1.0000	10,189		10,189		10,189
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	2,351		2,351		2,351
7			PECO Elec 3707 SM RES PA	1.0000	5,352	297	5,054	297	5,649
8			PECO Elec 3708 SM SCI PA	1.0000	863	8	855	8	871
9			PECO Elec 3709 SM LCI PA	1.0000	1,132	56	1,076	56	1,189
10			PECO Elec Dist-ARC EXP PA	1.0000	(3)		(3)		(3)
11			PECO Electric 3611 PA	1.0000	1,257	267	990	267	1,524
12			PECO Electric 3612 PA	1.0000	2,553	115	2,438	115	2,668
13			PECO Electric 3613 PA	1.0000	206	1	205	1	207
14			PECO Electric 3620 PA	1.0000	21,678	233	21,445	233	21,911
15			PECO Electric 3640 PA	1.0000	22,749	1,320	21,429	1,320	24,069
16			PECO Electric 3650 PA	1.0000	36,963	1,972	34,991	1,972	38,935
17			PECO Electric 3660 PA	1.0000	8,764	297	8,467	297	9,062
18			PECO Electric 3670 PA	1.0000	32,674	1,318	31,356	1,318	33,992
19			PECO Electric 3680 PA	1.0000	16,583	1,096	15,487	1,096	17,679
20			PECO Electric 3691 PA	1.0000	3,453	114	3,339	114	3,568
21			PECO Electric 3692 PA	1.0000	4,919	32	4,887	32	4,950
22			PECO Electric 3701 PA	1.0000	145	7	138	7	152
23			PECO Electric 3710 PA	1.0000	4		4		4
24			PECO Electric 3730 PA	1.0000	884	7	877	7	892
25			PECO Electric 3731 PA	1.0000	76	0	76	0	76
26			PECO Electric 3732 PA	1.0000	925	(26)	951	(26)	900
27			PECO Electric 3733 PA	1.0000	36		36		36
28			Sub-total Electric - Distribution		$181,419	$8,442	$172,977	$8,442	$189,862
29			Sub-total Electric - Distribution		$181,419	$8,442	$172,977	$8,442	$189,862
30									
31		Common - General Plant	PECO Common 3901 PA	0.7693	$3,179	($12)	$3,192	($12)	$3,167
32			PECO Common 3902 IL	0.7693	13		13		13
33			PECO Common 3902 PA	0.7693	1,887	223	1,665	223	2,110
34			PECO Common 3903 PA	0.7693	44	4	40	4	48
35			PECO Common 3911 PA	0.7693	10		10		10
36			PECO Common 3912 PA	0.7693	1,635	79	1,556	79	1,714
37			PECO Common 3913 IL	0.7693	812	50	763	50	862
38			PECO Common 3913 PA	0.7693	5,569	1,124	4,445	1,124	6,693
39			PECO Common 3930 PA	0.7693	80	7	73	7	87
40			PECO Common 3941 PA	0.7693	2		2		2
41			PECO Common 3942 PA	0.7693	51		51		51
42			PECO Common 3970 PA	0.7693	4,378	107	4,271	107	4,485

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
43			PECO Common 3980 PA	0.7693	65		65		65
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	1.0000	18		18		18
45			PECO Elec 3919 SM Comp Equip IL	1.0000	36		36		36
46			PECO Elec 3919 SM Comp Equip MD	1.0000	13		13		13
47			PECO Elec 3919 SM Comp Equip NC	1.0000	7		7		7
48			PECO Elec 3919 SM Comp Equip PA	1.0000	11		11		11
49			PECO Elec 3949 SM Tools PA	1.0000	7		7		7
50			PECO Elec 3979 SM Comm Equip PA	1.0000	2,649	9	2,640	9	2,658
51			PECO Electric 3901 PA	1.0000	802	9	793	9	810
52			PECO Electric 3902 PA	1.0000	393	2	391	2	395
53			PECO Electric 3903 PA	1.0000	5	4	1	4	8
54			PECO Electric 3911 PA	1.0000	1		1		1
55			PECO Electric 3912 PA	1.0000	64	5	59	5	69
56			PECO Electric 3913 PA	1.0000	6,894	273	6,621	273	7,166
57			PECO Electric 3930 PA	1.0000	4		4		4
58			PECO Electric 3940 PA	1.0000	3,475	225	3,250	225	3,700
59			PECO Electric 3951 PA	1.0000	13		13		13
60			PECO Electric 3952 PA	1.0000	1		1		1
61			PECO Electric 3970 PA	1.0000	7,628	122	7,505	122	7,750
62			PECO Electric 3980 PA	1.0000	61	2	59	2	63
63			Sub-total Electric - General Plant		$39,807	$2,231	$37,576	$2,231	$42,037
64			Sub-total Electric - General Plant		$39,807	$2,231	$37,576	$2,231	$42,037
65									
66		Electric - Transmission	PECO Electric 3521 PA	1.0000	$402	($3)	$406	($3)	$399
67			PECO Electric 3522 MD	1.0000	1		1		1
68			PECO Electric 3522 NJ	1.0000	0		0		0
69			PECO Electric 3522 PA	1.0000	1,458	19	1,439	19	1,477
70			PECO Electric 3523 NJ	1.0000	0		0		0
71			PECO Electric 3523 PA	1.0000	49	1	48	1	49
72			PECO Electric 3530 NJ	1.0000	66		66		66
73			PECO Electric 3530 PA	1.0000	17,720	203	17,518	203	17,923
74			PECO Electric 3540 DE	1.0000	92		92		92
75			PECO Electric 3540 MD	1.0000	52		52		52
76			PECO Electric 3540 NJ	1.0000	217		217		217
77			PECO Electric 3540 PA	1.0000	3,098	1	3,097	1	3,099
78			PECO Electric 3550 PA	1.0000	421	19	402	19	440
79			PECO Electric 3560 DE	1.0000	5		5		5
80			PECO Electric 3560 MD	1.0000	12		12		12
81			PECO Electric 3560 NJ	1.0000	127	37	90	37	164
82			PECO Electric 3560 PA	1.0000	4,079	99	3,980	99	4,179
83			PECO Electric 3570 PA	1.0000	633	379	253	379	1,012
84			PECO Electric 3580 PA	1.0000	2,079	414	1,665	414	2,493

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
85			PECO Electric 3590 NJ	1.0000	4		4		4
86			PECO Electric 3590 PA	1.0000	24	(6)	30	(6)	19
87			Sub-total Electric - Transmission		$30,540	$1,163	$29,377	$1,163	$31,703
88									
89			Sub-total 403.0 Depreciation Expense		$251,766	$11,836	$239,930	$11,836	$263,602
90			Sub-total Electric - Transmission		$30,540	$1,163	$29,377	$1,163	$31,703
91									
97	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 3030- North Star RE SW	0.7693	344		344		344
98			PECO Com 3030-Apollo SW	0.7693	527	527		527	1,053
99			PECO Com 3030-BIDA Customer Project	0.7693	1,423		1,423		1,423
100			PECO Com 3030-BIDA-AMI Ph2 SW	0.7693	1,645		1,645		1,645
101			PECO Com 3030-CIS Transformation SW	0.7693	157		157		157
102			PECO Com 3030-Cloud Serv 3 yr	0.7693	1,510	825	684	825	2,335
103			PECO Com 3030-Cloud Serv 5 yr	0.7693	2,139	1,044	1,095	1,044	3,183
104			PECO Com 3030-Common MDM SW	0.7693	6,392	168	6,224	168	6,560
105			PECO Com 3030-CTA PHI Consol SW	0.7693	14		14		14
106			PECO Com 3030-Cust Appt Sched SW	0.7693	473		473		473
107			PECO Com 3030-Digital Strat Platfor	0.7693	94		94		94
108			PECO Com 3030-EU Dig Strat EPay SW	0.7693	342		342		342
109			PECO Com 3030-EU Digital Program We	0.7693	1,274	664	610	664	1,939
110			PECO Com 3030-EU oneMDS SW	0.7693	2,122	2,122		2,122	4,245
111			PECO Com 3030-Fusion Mig Non-MDM SW	0.7693	609		609		609
112			PECO Com 3030-I Sign Up and Move	0.7693	1,207		1,207		1,207
113			PECO Com 3030-IT Cust Mobile App SW	0.7693	79	51	27	51	130
114			PECO Com 3030-IVR System PA	0.7693	98	76	22	76	174
115			PECO Com 3030-Lease IT SW	0.7693	86		86		86
116			PECO Com 3030-Misc 5 yr FR PA	0.7693	5,219	(1,996)	7,216	(1,996)	3,223
117			PECO Com 3030-Misc 5 yr PA	0.7693	10	10		10	19
118			PECO Com 3030-Mobile Dispatch Mappi	0.7693	4,494		4,494		4,494
119			PECO Com 3030-OBIEE Migration SW	0.7693	846		846		846
120			PECO Com 3030-Oracle MW Upgrade SW	0.7693	200		200		200
121			PECO Com 3030-Rev Req Filing SW	0.7693	300		300		300
122			PECO Com 3030-Robotic Process Auto	0.7693	68		68		68
123			PECO Com 3030-SCP Splunk SW	0.7693	2		2		2
124			PECO Elec 303 Elec Configuration SW	1.0000	551		551		551
125			PECO Elec 303 EV-FC	1.0000	70		70		70
126			PECO Elec 303 NERC CIP Systems D PA	1.0000	2		2		2
127			PECO Elec 303 NERC CIP Systems PA	1.0000	17		17		17
128			PECO Elec 303 SLC	1.0000	111		111		111
129			PECO Elec 303 SM AMOS PA	1.0000	379		379		379
130			PECO Elec 303-BIDA Grid T&D Domain	1.0000	1,762		1,762		1,762
131			PECO Elec 303-CFP - Outage SW D	1.0000	86	86		86	172

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
132			PECO Elec 303-CFP - Outage SW T	1.0000	15	15		15	30
133			PECO Elec 303-Dist Auto Ntwk Upg Hi	1.0000	763		763		763
134			PECO Elec 303-EMS Implementation Pr	1.0000	3,321		3,321		3,321
135			PECO Elec 303-EU Custom Analytics S	1.0000	278		278		278
136			PECO Elec 303-EU Digital Solar Tool	1.0000	327		327		327
137			PECO Elec 303-EU Load Forecast SW	1.0000	723		723		723
138			PECO Elec 303-EU Ratings DB SW D	1.0000	12		12		12
139			PECO Elec 303-EU Ratings DB SW T	1.0000	155		155		155
140			PECO Elec 303-EU TOA Implementation	1.0000	995		995		995
141			PECO Elec 303-PECO RNI Upgrade SW D	1.0000	1,380		1,380		1,380
142			PECO Elec 303-PECO TOU SW	1.0000	1,370		1,370		1,370
143			PECO Elec 303-SES IV D SW	1.0000	2,364		2,364		2,364
144			PECO Elec 3030 - BIDA Smart Energy A (Original)	1.0000	459		459		459
145			PECO Elec 3030-Cloud Serv 3 yr	1.0000	254		254		254
146			PECO Elec 3030-Cloud Serv 5 yr	1.0000	443	91	352	91	534
147			PECO Electric 303 Misc 5 FR PA	1.0000	3,484	384	3,099	384	3,868
148			Sub-total Electric - Intangible Plant		$50,995	$4,067	$46,928	$4,067	$55,063
149									
150			Sub-total 404.0 Amort. of Limited-Term Electric Plant		$50,995	$4,067	$46,928	$4,067	$55,063
151									
152			**Total**		$302,761	$15,903	$286,858	$15,903	$318,665
153			Sub-total Electric - Intangible Plant		$50,995	$4,067	$46,928	$4,067	$55,063
154									
155			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.		$50,995	$4,067	$46,928	$4,067	$55,063

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$1,229	$216	$1,012	$216	$1,445
2			PECO Elec 3650 PA LTIIP	1.0000	$2,240	180	2,060	180	2,420
3			PECO Elec 3660 PA LTIIP	1.0000	$1,473	423	1,050	423	1,896
4			PECO Elec 3670 PA LTIIP	1.0000	$2,723	507	2,216	507	3,230
5			PECO Elec 3705 SM UD RES PA	1.0000	$10,189		10,189		10,189
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	$2,351		2,351		2,351
7			PECO Elec 3707 SM RES PA	1.0000	$5,352	297	5,054	297	5,649
8			PECO Elec 3708 SM SCI PA	1.0000	$863	8	855	8	871
9			PECO Elec 3709 SM LCI PA	1.0000	$1,132	56	1,076	56	1,189
10			PECO Elec Dist-ARC EXP PA						
11			PECO Electric 3611 PA	1.0000	$1,257	267	990	267	1,524
12			PECO Electric 3612 PA	1.0000	$2,553	115	2,438	115	2,668
13			PECO Electric 3613 PA	1.0000	$206	1	205	1	207
14			PECO Electric 3620 PA	1.0000	$21,678	233	21,445	233	21,911
15			PECO Electric 3640 PA	1.0000	$22,749	1,320	21,429	1,320	24,069
16			PECO Electric 3650 PA	1.0000	$36,963	1,972	34,991	1,972	38,935
17			PECO Electric 3660 PA	1.0000	$8,764	297	8,467	297	9,062
18			PECO Electric 3670 PA	1.0000	$32,674	1,318	31,356	1,318	33,992
19			PECO Electric 3680 PA	1.0000	$16,583	1,096	15,487	1,096	17,679
20			PECO Electric 3691 PA	1.0000	$3,453	114	3,339	114	3,568
21			PECO Electric 3692 PA	1.0000	$4,919	32	4,887	32	4,950
22			PECO Electric 3701 PA	1.0000	$145	7	138	7	152
23			PECO Electric 3710 PA	1.0000	$4		4		4
24			PECO Electric 3730 PA	1.0000	$884	7	877	7	892
25			PECO Electric 3731 PA	1.0000	$76	0	76	0	76
26			PECO Electric 3732 PA	1.0000	$925	(26)	951	(26)	900
27			PECO Electric 3733 PA	1.0000	$36		36		36
28			Sub-total Electric - Distribution		$181,423	$8,442	$172,980	$8,442	$189,865
29			Sub-total Electric - Distribution		$181,423	$8,442	$172,980	$8,442	$189,865
30									
31		Common - General Plant	PECO Common 3901 PA	0.8763	$2,786	($11)	$2,797	($11)	$2,775
32			PECO Common 3902 IL	0.8763	11		11		11
33			PECO Common 3902 PA	0.8763	1,654	195	1,459	195	1,849
34			PECO Common 3903 PA	0.8763	38	4	35	4	42
35			PECO Common 3911 PA	0.8763	9		9		9
36			PECO Common 3912 PA	0.8763	1,433	69	1,364	69	1,502
37			PECO Common 3913 IL	0.8763	712	44	668	44	755
38			PECO Common 3913 PA	0.8763	4,880	985	3,895	985	5,865
39			PECO Common 3930 PA	0.8763	70	6	64	6	76
40			PECO Common 3941 PA	0.8763	2		2		2
41			PECO Common 3942 PA	0.8763	45		45		45
42			PECO Common 3970 PA	0.8763	3,836	94	3,743	94	3,930

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
43			PECO Common 3980 PA	0.8763	57		57		57
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	0.8763	16		16		16
45			PECO Elec 3919 SM Comp Equip IL	0.8763	32		32		32
46			PECO Elec 3919 SM Comp Equip MD	0.8763	11		11		11
47			PECO Elec 3919 SM Comp Equip NC	0.8763	6		6		6
48			PECO Elec 3919 SM Comp Equip PA	0.8763	10		10		10
49			PECO Elec 3949 SM Tools PA	0.8763	6		6		6
50			PECO Elec 3979 SM Comm Equip PA	0.8763	2,321	8	2,314	8	2,329
51			PECO Electric 3901 PA	0.8763	702	8	695	8	710
52			PECO Electric 3902 PA	0.8763	344	1	343	1	346
53			PECO Electric 3903 PA	0.8763	4	3	1	3	7
54			PECO Electric 3911 PA	0.8763	1		1		1
55			PECO Electric 3912 PA	0.8763	56	4	52	4	60
56			PECO Electric 3913 PA	0.8763	6,041	239	5,802	239	6,280
57			PECO Electric 3930 PA	0.8763	4		4		4
58			PECO Electric 3940 PA	0.8763	3,045	197	2,848	197	3,243
59			PECO Electric 3951 PA	0.8763	12		12		12
60			PECO Electric 3952 PA	0.8763	1		1		1
61			PECO Electric 3970 PA	0.8763	6,684	107	6,577	107	6,791
62			PECO Electric 3980 PA	0.8763	54	2	52	2	55
63			Sub-total Electric - General Plant		$34,882	$1,955	$32,927	$1,955	$36,836
64			Sub-total Electric - General Plant		$34,882	$1,955	$32,927	$1,955	$36,836
65									
66		Electric - Transmission	PECO Electric 3521 PA						
67			PECO Electric 3522 MD						
68			PECO Electric 3522 NJ						
69			PECO Electric 3522 PA						
70			PECO Electric 3523 NJ						
71			PECO Electric 3523 PA						
72			PECO Electric 3530 NJ						
73			PECO Electric 3530 PA						
74			PECO Electric 3540 DE						
75			PECO Electric 3540 MD						
76			PECO Electric 3540 NJ						
77			PECO Electric 3540 PA						
78			PECO Electric 3550 PA						
79			PECO Electric 3560 DE						
80			PECO Electric 3560 MD						
81			PECO Electric 3560 NJ						
82			PECO Electric 3560 PA						
83			PECO Electric 3570 PA						
84			PECO Electric 3580 PA						

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
85			PECO Electric 3590 NJ						
86			PECO Electric 3590 PA						
87			Sub-total Electric - Transmission						
88									
89			Sub-total 403.0 Depreciation Expense		$216,304	$10,397	$205,907	$10,397	$226,701
90			Sub-total Electric - Transmission						
91									
97	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	PECO Com 3030- North Star RE SW	0.8763	302		302		302
98			PECO Com 3030-Apollo SW	0.8763	462	462		462	923
99			PECO Com 3030-BIDA Customer Project	0.8763	1,247		1,247		1,247
100			PECO Com 3030-BIDA-AMI Ph2 SW	0.8763	1,442		1,442		1,442
101			PECO Com 3030-CIS Transformation SW	0.8763	138		138		138
102			PECO Com 3030-Cloud Serv 3 yr	0.8763	1,323	723	600	723	2,046
103			PECO Com 3030-Cloud Serv 5 yr	0.8763	1,874	915	959	915	2,789
104			PECO Com 3030-Common MDM SW	0.8763	5,601	147	5,454	147	5,749
105			PECO Com 3030-CTA PHI Consol SW	0.8763	13		13		13
106			PECO Com 3030-Cust Appt Sched SW	0.8763	415		415		415
107			PECO Com 3030-Digital Strat Platfor	0.8763	83		83		83
108			PECO Com 3030-EU Dig Strat EPay SW	0.8763	299		299		299
109			PECO Com 3030-EU Digital Program We	0.8763	1,117	582	535	582	1,699
110			PECO Com 3030-EU oneMDS SW	0.8763	1,860	1,860		1,860	3,719
111			PECO Com 3030-Fusion Mig Non-MDM SW	0.8763	533		533		533
112			PECO Com 3030-I Sign Up and Move	0.8763	1,057		1,057		1,057
113			PECO Com 3030-IT Cust Mobile App SW	0.8763	69	45	24	45	114
114			PECO Com 3030-IVR System PA	0.8763	86	66	20	66	152
115			PECO Com 3030-Lease IT SW	0.8763	75		75		75
116			PECO Com 3030-Misc 5 yr FR PA	0.8763	4,574	(1,749)	6,323	(1,749)	2,824
117			PECO Com 3030-Misc 5 yr PA	0.8763	8	8		8	17
118			PECO Com 3030-Mobile Dispatch Mappi	0.8763	3,938		3,938		3,938
119			PECO Com 3030-OBIEE Migration SW	0.8763	741		741		741
120			PECO Com 3030-Oracle MW Upgrade SW	0.8763	176		176		176
121			PECO Com 3030-Rev Req Filing SW	0.8763	263		263		263
122			PECO Com 3030-Robotic Process Auto	0.8763	60		60		60
123			PECO Com 3030-SCP Splunk SW	0.8763	2		2		2
124			PECO Elec 303 Elec Configuration SW	1.0000	551		551		551
125			PECO Elec 303 EV-FC	1.0000	70		70		70
126			PECO Elec 303 NERC CIP Systems D PA	1.0000	2		2		2
127			PECO Elec 303 NERC CIP Systems PA						
128			PECO Elec 303 SLC	1.0000	111		111		111
129			PECO Elec 303 SM AMOS PA	1.0000	379		379		379
130			PECO Elec 303-BIDA Grid T&D Domain	0.8763	1,544		1,544		1,544
131			PECO Elec 303-CFP - Outage SW D	1.0000	86	86		86	172

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
132			PECO Elec 303-CFP - Outage SW T						
133			PECO Elec 303-Dist Auto Ntwk Upg Hi	1.0000	763		763		763
134			PECO Elec 303-EMS Implementation Pr						
135			PECO Elec 303-EU Custom Analytics S	1.0000	278		278		278
136			PECO Elec 303-EU Digital Solar Tool	1.0000	327		327		327
137			PECO Elec 303-EU Load Forecast SW	1.0000	723		723		723
138			PECO Elec 303-EU Ratings DB SW D	1.0000	12		12		12
139			PECO Elec 303-EU Ratings DB SW T						
140			PECO Elec 303-EU TOA Implementation						
141			PECO Elec 303-PECO RNI Upgrade SW D	1.0000	1,380		1,380		1,380
142			PECO Elec 303-PECO TOU SW	1.0000	1,370		1,370		1,370
143			PECO Elec 303-SES IV D SW	1.0000	2,364		2,364		2,364
144			PECO Elec 3030 - BIDA Smart Energy A (Original)	1.0000	459		459		459
145			PECO Elec 3030-Cloud Serv 3 yr	0.8763	223		223		223
146			PECO Elec 3030-Cloud Serv 5 yr	0.8763	388	80	308	80	468
147			PECO Electric 303 Misc 5 FR PA	0.8763	3,053	337	2,716	337	3,389
148			Sub-total Electric - Intangible Plant		$41,838	$3,562	$38,276	$3,562	$45,400
149									
150			Sub-total 404.0 Amort. of Limited-Term Electric Plant		$41,838	$3,562	$38,276	$3,562	$45,400
151									
152			**Total**		$258,142	$13,959	$244,183	$13,959	$272,101
153			Sub-total Electric - Intangible Plant		$41,838	$3,562	$38,276	$3,562	$45,400
154									
155			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.		$41,838	$3,562	$38,276	$3,562	$45,400

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Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$2,934,674	$132,425	$3,067,099
2	Operating Expenses		2,471,689	9,377	2,481,066
3	OIBIT	L1 - L2	$462,986	$123,048	$586,033
4					
5	Rate Base		$6,860,054		$6,860,054
6	Weighted Cost of Debt		1.990%		1.990%
7	Synchronized Interest Expense	L5 * L6	$136,515		$136,515
8	Base Taxable Income	L3 - L7	$326,470	$123,048	$449,518
9					
10	State Accelerated Tax Depreciation		$348,439		$348,439
11	Pro Forma Book Depreciation		272,101		272,101
12	State Tax Depreciation (Over) Under Book	L11 - L10	($76,338)		($76,338)
13	Regulatory Asset Programs M-1, Pension and Post Retirement & Other		(71,911)		(71,911)
14	Other Property Basis Adjustments (CIAC/ICM)		(33,099)		(33,099)
15	Removal Costs/Software		(14,711)		(14,711)
16	AFUDC Equity		(20,762)		(20,762)
17	Permanent Adjustments		3,682		3,682
18	Repair Deduction		(196,210)		(196,210)
19					
20	State Taxable Income	L8 + SUM (L12 to L18)	($82,878)	$123,048	$40,169
21					
22	State Income Tax Rate		8.99%	8.99%	8.99%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L22 * L20)	$7,451	($11,062)	($3,611)
24	Net Operating Loss Utilization %		40.00%	40.00%	40.00%
25	Net Operating Loss Utilization	- L24 * L23	(2,980)	4,425	1,444
26	State Income Tax Benefit / (Expense)	L23 + L25	$4,470	($6,637)	($2,167)
27					
28	Federal Accelerated Tax Depreciation		$326,784		$326,784
29	Pro Forma Book Depreciation		272,101		272,101
30	Federal Tax Deducts (Over) Under Book	L29 - L28	($54,683)		($54,683)
31	Regulatory Asset Programs M-1		(71,911)		(71,911)
32	Other Property Basis Adjustments (CIAC/ICM)		(33,099)		(33,099)
33	Removal Costs/Software		(14,711)		(14,711)
34	AFUDC Equity		(20,762)		(20,762)
35	Permanent Adjustments		3,682		3,682
36	Repair Deduction		(196,210)		(196,210)
37	Federal NOL				
38	Federal Taxable Income	L8 + L26 + SUM (L30 to L37)	($56,752)	$116,411	$59,658
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	- (L38 * L40)	$11,918	($24,446)	($12,528)
42	Corporate Alternative Minimum Tax		($60,332)		($60,332)
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	($43,943)	($31,083)	($75,027)
44					

Line No.	Description	Reference	Present Rates	Rate Increase	Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($35,268)	$929	(34,339)
47	Deferred Taxes on Timing Differences- State		(9,440)		(9,440)
48	Deferred Taxes on State NOL		2,980	(4,425)	(1,444)
49	Excess Deferred Amortization		6,791		6,791
50	Excess Deferred Amortization - State (Net of Federal)		232		232
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax Expense on Flow Through Adjustment		1,246		1,246
53	Corporate Alternative Minimum Tax		60,332		60,332
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	$26,872	($3,496)	$23,376
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	($17,072)	($34,579)	($51,651)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		$15		$15
60					
61	Combined Income Tax Benefit / (Expense)	SUM L56 to L59	($17,056)	($34,579)	($51,635)
62					
63	**Federal Income Tax Benefit / (Expense)**	L41 + L46 + L49 + L51 + L52 + L59	**($15,298)**	**($23,517)**	**($38,815)**
64	**State Income Tax Benefit / (Expense)**	L26 + L47 + L48 + L50	**($1,758)**	**($11,062)**	**($12,820)**
65	**Total Income Tax Benefit / (Expense)**	L63 + L64	**($17,056)**	**($34,579)**	**($51,635)**

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		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Reference	2018	2019	2020	2021	2022	Average
1	PECO Consolidated Taxable Income		$149,524	$191,310	($22,448)	$33,306	$135,993	
2								
3								
4	Consolidated Income Companies Taxable Income		$1,005,422	$931,575	$937,098	$1,705,766	$816,851	
5								
6								
7	Taxable Income Percentage to PECO	L1 / L4	14.87%	20.54%		1.95%	16.65%	
8								
9								
10	Consolidated Companies Loss		$ (85,736)	$ (162,524)	$ (249,053)	$ (575,746)	$ (108,853)	
11								
12								
13	PECO Allocation of Loss	L7 * L10	$ (12,750)	$ (33,376)	$ -	$ (11,242)	$ (18,122)	
14								
15								
16	Electric Percentage		106.61%	125.46%	-88.07%	376.30%	158.98%	
17								
18								
19	Loss Allocable to Electric	L13 * L16	($13,593)	($41,874)		($42,303)	($28,809)	
20								
21								
22								
23	Average for 2018 to 2022	Average L19						(25,316)
24								
25								
26	Tax Rate							21.00%
27								
28	**Section 1301.1(b) Differential**	L23 * L26						**$ (5,316)**

		(1)	(2)
Line No.	Description	Reference	Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		16,337
4	Total Customer Revenue		2,895,142
5	Shopping Revenue		1,016,077
6	LPC REVENUE	L3 / (L4 + L5)	0.004177
7	GROSS RECEIPTS TAX		(0.059000)
8	UNCOLLECTIBLE EXPENSES	D-10	(0.009708)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.002397)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.933072
13			
14	STATE INCOME TAX RATE		8.990%
15			
16	STATE INCOME TAX FACTOR	-	(0.083883)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.849189
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	-	(0.178330)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.670859
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.490625
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	26.221%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		8.990%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.089900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.910100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.191121)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.718979
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.390861
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	28.102%

Line No.	Description	Reference	(1) Present Rates	(2) Revenue Increase	(3) Total
1	**MEASURE OF VALUE**				
□	Utility Plant	C-2	$11,242,906		$11,242,906
□	Accumulated Depreciation	C-3	2,253,728		2,253,728
□	Common Plant - Net of Accum Depr	C-8	555,965		555,965
□	Net Plant in service	L2 - L3 + L4	$9,545,143		$9,545,143
□					
□	Working Capital	C-1	$214,819		$214,819
□	Accum Deferred Income Taxes	C-1	(596,644)		(596,644)
□	Customer Deposits	C-1	(57,291)		(57,291)
10	Customer Advances for Construction	C-1	(2,889)		(2,889)
11	Materials and Supplies	C-1	30,350		30,350
1□	Accum Deferred Income Taxes - Reg Liability	C-1	(277,875)		(277,875)
1□					
1□	TOTAL RATE BASE	SUM L5 to L12	$8,855,613		$8,855,613
1□					
1□	**OPERATING REVENUES AND EXPENSES**				
1□	Base Customer Charges	D-5	$1,788,999	$462,798	$2,251,797
1□	Electric Cost Revenue	D-5	$1,071,200		1,071,200
1□	Other Operating Revenues	D-5	$48,022	1,403	49,425
□0	Total Revenues	SUM L17 to L19	$2,908,221	$464,202	$3,372,423
□1					
□□	Operating Expenses	D-1	$2,532,993	$32,907	$2,565,900
□□					
□□	OIBIT	L20 - L22	$375,228	$431,294	$806,522
□□					
□□	Income Taxes @ Eff Inc Tax Rate	D-18	$17,951		$17,951
□□	Income Taxes @ Statutory Rates	D-18		($117,796)	($117,796)
□□					
□□	NET OPERATING INCOME	SUM L24 to L27	$393,179	$313,499	$706,678
□0					
□1	RATE OF RETURN	L29 / L14	4.44%		7.98%
□□					
□□	**REVENUE INCREASE REQUIRED**				
□□	Rate of Return at Present Rates	L31	4.44%		
□□					
□□	Rate of Return Required	B-7	7.98%		
□□					
□□	Change in ROR	L36 - L34	3.54%		
□□					
□0	Change in Operating Income	L14 * L38	$313,499		
□1					
□□	Gross Revenue Conversion Factor	D-19	1.476		
□□					
□□	Change in Revenues	L40 * L42	$462,798		
□□					
□□	**RETURN ON COMMON EQUITY**				
□□	Common Equity Ratio	B-7	53.40%		
□□	Common Equity Rate Base	L14 * L47	$4,728,898		
□□	NET OPERATING INCOME	L29	$393,179		
□0	Synchronized Interest Expense	D-18	$188,625		
□1	NET OPERATING INCOME - COMMON EQUITY	L49 - L50	$204,555		
□□	RATE OF RETURN ON COMMON EQUITY	L51 / L48	4.33%		

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$20,062,028
3	Construction Work In Progress (107)		659,623
4	Total Utility Plant	L2 + L3	$20,721,651
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		5,007,287
6	Net Utility Plant	L4 - L5	$15,714,364
7			
8	**Other Property and Investments**		
9	Non-Utility Property (121)		$11,249
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,448
11	Invest in Assoc Company (123)		7,725
12	Other Investments (124-129, 175-176)		27,679
13	Total Other Property and Investments	SUM L9 to L12	$45,204
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments (131-136)		$25,000
17	Customer Accounts Receivable (142)		442,289
18	Other Accounts Receivable (143)		35,649
19	Accum. Prov. for Uncollectible (144)		(83,303)
20	Receivables from Assoc. Comp. (146)		
21	Fuel Stock (151)		38,067
22	Plant Materials & Supplies (154)		69,125
23	Prepayments (165)		20,632
24	Accrued Utility Revenues (173)		215,498
25	Miscellaneous Current & Accrued Assets (174)		87,744
26	Total Current and Accrued Assets	SUM L16 to L25	$850,700
27			
28	**Deferred Debits**		
29	Unamortized Debt Expense (181)		$54,014
30	Other Regualtory Assets (182.3)		1,123,689
31	Miscellaneous Deferred Debits (186)		740,795
32	Unamortized Loss on Reacquired Debt (189)		636
33	Accumulated Deferred Income Taxes (190)		(0)
34	Total Deferred Debits	SUM L29 to L33	$1,919,133
35			
36	**TOTAL ASSETS**	L6+L13+L26+L34	$18,529,402

		(1)	(2)
Line No.	Description	Reference	Total - PECO
37	**Proprietary Capital**		
38	Common Stock Issued (201)		$1,423,004
39	Preferred Stock Issued (204)		
40	Other Paid-In Capital (208-211)		3,703,533
41	Capital Stock Expense (214)		(87)
42	Retained Earnings (215, 215.2, 216)		2,419,374
43	Unappropriated Undistributed Subsidiary Earnings (216.1)		
44	Accum Other Comprehensive Income (219)		
45	Total Propriety Capital & Margins	SUM L38 to L44	$7,545,824
46			
47	**Long Term Debt**		
48	Bonds (221)		$6,400,000
49	Advances from Associated Companies (223)		184,419
50	Other Long-Term Debt (224)		
51	Unamortized Premium on LTD (225)		
52	Unamortized Discount on LTD (226)		(21,980)
53	Total Long-Term Debt	SUM L48 to L52	$6,562,439
54			
55	**Other Non-Current Liabilities**		
56	Obligations under Capital Leases (227)		
57	Accum. Prov for Injuries & Damages (228.2)		$35,157
58	Accum. Prov for Pensions & Benefits (228.3)		303,426
59	Accum. Miscellaneous Operating Prov (228.4)		18,397
60	Asset Retirement Obligation (230)		26,348
61	Total Other Non-Current Liabilities	SUM L56 to L60	$383,328
62			
63	**Current and Accrued Liabilities**		
64	Notes Payable (231)		$150,436
65	Accounts Payable (232)		648,728
66	Notes Payable to Assoc. Companies (233)		
67	Accounts Payable to Assoc. Companies (234)		36,168
68	Customer Deposits (235)		78,872
69	Taxes Accrued (236)		(919)
70	Interest Accrued (237)		73,493
71	Dividends Declared (238)		
72	Tax Collections Payable (241)		33
73	Misc Current & Accrued Liabilities (242)		182,695
74	Total Current & Accrued Liabilities	SUM L64 to L73	$1,169,506
75			
76	**Other Deferred Credits**		
77	Customer Advances for Construction (252)		$4,172
78	Other Deferred Credits (253)		5,796
79	Other Regulatory Liabilities (254)		282,725
80	Deferred Investment Tax Credit (255)		286
81	Unamortized Gain on Reacquired Debt (257)		
82	Accumulated Deferred Income Taxes (281-283)		2,575,325
83	Total Other Deferred Credits	SUM L77 to L82	$2,868,304
84			
85	**TOTAL LIABILITIES AND OTHER CREDITS**	L45+L53+L61+L74+L83	$18,529,402

Line No.	Category	Description	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$1,678,305		$1,678,305
2		Electric Cost Revenue	1,071,200		1,071,200
3		Transmission - All Classes	199,791		199,791
4		Other Revenues	326,479	$278,457	48,022
5		Total Operating Revenues	$3,275,775	$278,457	$2,997,318
6					
7	**Total Operating Expenses**	Operation & Maintenance Expenses	$2,138,595	$89,358	$2,049,237
8		Depreciation & Amortization Expense	368,879	49,882	318,997
9		Amortization of Regulatory Expense			
10		Taxes Other Than Income Taxes - Other	202,036	4,519	197,517
11		Total Operating Expenses	$2,709,509	$143,758	$2,565,751
12					
13	**Net Utility Operating Income Before Income Tax**		**$566,265**	**$134,698**	**$431,567**

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	440.0	$952,140		$952,140
2			Residential - House Heating	440.1	183,381		183,381
3			C & I Small	442.0	293,772		293,772
4			C & I Large	442.1	218,495		218,495
5			Street Lighting	444.0	8,121		8,121
6			Railroads & Railways	446.0	22,396		22,396
7			Intercompany	448.0			
8			Transmission - All Classes		199,791		199,791
9			Sub-total - Customer & Distribution Revenues		$1,878,096		$1,878,096
10							
11		Electric Cost Revenue	Residential	440.0	$689,404		$689,404
12			Residential - House Heating	440.1	180,937		180,937
13			C & I Small	442.0	148,035		148,035
14			C & I Large	442.1	52,022		52,022
15			Street Lighting	444.0	801		801
16			Intercompany	448.0			
17			Sub-total - Electric Cost Revenue		$1,071,200		$1,071,200
18							
19		Other Operating Revenues	Forfeited Discounts	450.0	$12,224		$12,224
20			Miscellaneous Service Revenues	451.0	3,684		3,684
21			Rent For Electric Property	454.0	33,265	$10,685	22,580
22			Other Electric Revenues	456.0	9,534		9,534
23			Transmission of Electricity for Others	456.1	267,772	267,772	
24			Sub-total - Other Operating Revenues		$326,479	$278,457	$48,022
25							
26			**TOTAL OPERATING REVENUES**		$3,275,775	$278,457	$2,997,318
27							

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FPFTY Amount	Non-Jurisdictional	Jurisdictional
28	**Operating Expenses**	Operation & Maintenance Expenses	Purchased Power	555.0	$1,003,713		$1,003,713
29			Operation & Supervision	560.0	8,806	$8,806	
30			Load Dispatching	561.0			
31			Scheduling, System Control & Dispatch	561.4	93,988		93,988
32			Transmission Service Studies	561.6			
33			Generation Service Studies	561.7			
34			Reliability, Planning & Standard Development	561.8	92,919		92,919
35			Station Expense	562.0	490	490	
36			Overhead Lines	563.0	637	637	
37			Underground Lines Expense	564.0			
38			Miscellaneous Expense	566.0	17,917	17,917	
39			Rents	567.0	15,996	15,996	
40			Maintenance of Structures	569.0	(38)	(38)	
41			Maintenance of Computer Hardware	569.1	84	84	
42			Maintenance of Computer Software	569.2	84	84	
43			Maintenance of Communication Equipment	569.3	130	130	
44			Maintenance of Station Equipment	570.0	14,348	14,348	
45			Maintenance of Overhead Lines	571.0	12,081	12,081	
46			Maintenance of Underground Lines	572.0	240	240	
47			Maintenance of Misc Transmission Plant	573.0	11,432	11,432	
48			Operation & Supervision	580.0	1,271		1,271
49			Load Dispatching	581.0			
50			Station Expenses	582.0	816		816
51			Overhead Lines Expenses	583.0	17,513		17,513
52			Underground Lines Expense	584.0	14,687		14,687
53			Meter Expenses	586.0	7,801		7,801
54			Customer Installations Expense	587.0	14,386		14,386
55			Miscellaneous Expense	588.0	90,014		90,014
56			Rents	589.0	3,658		3,658
57			Maintenance of Structures	591.0	6,622		6,622
58			Maintenance of Station Equipment	592.0	18,529		18,529
59			Maintenance of Overhead Lines	593.0	189,290		189,290
60			Maintenance of Underground Lines	594.0	38,602		38,602

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FPFTY Amount	Non-Jurisdictional	Jurisdictional
61			Maintenance of Line Transformers	595.0	2,378		2,378
62			Maintenance of Street Lighting & Signal Systems	596.0	1,990		1,990
63			Maintenance of Misc. Distribution	598.0	20,293		20,293
64			Supervision	901.0			
65			Meter Reading	902.0	976		976
66			Customer Records and Collection	903.0	105,441		105,441
67			Uncollectible Accounts	904.0	38,095		38,095
68			Miscellaneous Customer Accounts	905.0	3,295		3,295
69			Customer Assistance	908.0	101,517		101,517
70			Informational & Instructional	909.0	1,407		1,407
71			Miscellaneous Customer & Informational	910.0	992		992
72			Demonstrating & Selling	912.0	414		414
73			Miscellaneous Sales	916.0			
74			Administrative and General Salaries	920.0	22,337	(7,552)	29,889
75			Office Supplies and Expenses	921.0	4,628	1,063	3,566
76			Administrative Expenses Transferred-Credit	922.0			
77			Outside Service Employed	923.0	98,279	10,130	88,149
78			Property Insurance	924.0	833	91	741
79			Injuries & Damages	925.0	12,396	75	12,322
80			Employee Pensions and Benefits	926.0	26,786	2,043	24,743
81			Regulatory Commission Expenses	928.0	9,839	288	9,551
82			Duplicate Charges-Credit	929.0	(1,634)	(542)	(1,092)
83			Miscellaneous General Expenses	930.2	3,134	607	2,527
84			Maintenance of General Plant	935.0	9,183	946	8,237
85				Sub-total - O&M Expenses	$2,138,595	$89,358	$2,049,237
86							

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
87		Depreciation & Amortization Expense	Depreciation & Amortization Expense	403.0	$309,959	$41,058	$268,901
88				404.0	58,920	8,824	50,096
89			Sub-total - Depreciation & Amortization Expense		$368,879	$49,882	$318,997
90							
91		Amortization of Regulatory Expense	Amortization of Regulatory Expense	407.3			
92			Sub-total - Amortization of Regulatory Expense				
93							
94		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	408.1	$202,036	$4,519	$197,517
95			Sub-total -Taxes Other Than Income Taxes - Other		$202,036	$4,519	$197,517
96							
97			**TOTAL OPERATING EXPENSES**		$2,709,509	$143,758	$2,565,751
98							
99			**NET UTILITY OPERATING INCOME BEFORE INCOME TAX**		**$566,265**	**$134,698**	**$431,567**
100							

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	440.0	$952,140		$952,140
2			Residential - House Heating	440.1	183,381		183,381
3			C & I Small	442.0	293,772		293,772
4			C & I Large	442.1	218,495		218,495
5			Railroads & Railways	446.0	8,121		8,121
6			Street Lighting	444.0	22,396		22,396
7			Intercompany	448.0			
8			Transmission - All Classes		199,791		199,791
9			Sub-total - Customer & Distribution Revenue		$1,878,096		$1,878,096
10							
11		**Electric Cost Revenue**	Residential	440.0	$689,404		$689,404
12			Residential - House Heating	440.1	180,937		180,937
13			C & I Small	442.0	148,035		148,035
14			C & I Large	442.1	52,022		52,022
15			Railroads & Railways	444.0			
16			Street Lighting	446.0	801		801
17			Intercompany	448.0			
18			Sub-total - Electric Cost Revenue		$1,071,200		$1,071,200
19							
20			**TOTAL OPERATING REVENUE**		$2,949,296		$2,949,296
21							
22	**OTHER REVENUE**	**Other Operating Revenue**	Forfeited Discounts	450.0	$12,224		$12,224
23			Miscellaneous Service Revenues	451.0	3,684		3,684
24			Sub-total - Other Operating Revenue		$15,908		$15,908
25							
26		**Other Electric Revenue**	Rent For Electric Property	454.0	$33,265	$10,685	$22,580
27			Other Electric Revenues	456.0	9,534		9,534
28			Transmission of Electricity for Others	456.1	267,772	267,772	
29			Sub-total - Other Electric Revenue		$310,571	$278,457	$32,114
30							
31			**TOTAL OTHER REVENUE**		$326,479	$278,457	$48,022
32							
33			**TOTAL REVENUE**		**$3,275,775**	**$278,457**	**$2,997,318**

Line No.	Category	Description	Account	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**POWER SUPPLY EXPENSES**	Power Supply	Purchased Power	555.0	$1,003,713		$1,003,713
2			**TOTAL POWER SUPPLY EXPENSES**		$1,003,713		$1,003,713
3							
4	**TRANSMISSION EXPENSE**	Transmission Operations	Operation & Supervision	560.0	$8,806	$8,806	
5			Load Dispatching	561.0			
6			Scheduling, System Control & Dispatch	561.4	93,988		93,988
7			Transmission Service Studies	561.6			
8			Generation Service Studies	561.7			
9			Reliability, Planning & Standard Development	561.8	92,919		92,919
10			Station Expense	562.0	490	490	
11			Overhead Lines	563.0	637	637	
12			Underground Lines Expense	564.0			
13			Miscellaneous Expense	566.0	17,917	17,917	
14			Rents	567.0	15,996	15,996	
15			Sub-total Transmission Operations	SUM L4 to L14	$230,754	$43,847	$186,907
16							
17		Transmission Maintenance	Maintenance of Structures	569.0	($38)	($38)	
18			Maintenance of Computer Hardware	569.1	84	84	
19			Maintenance of Computer Software	569.2	84	84	
20			Maintenance of Communication Equipment	569.3	130	130	
21			Maintenance of Station Equipment	570.0	14,348	14,348	
22			Maintenance of Overhead Lines	571.0	12,081	12,081	
23			Maintenance of Underground Lines	572.0	240	240	
24			Maintenance of Misc Transmission Plant	573.0	11,432	11,432	
25			Sub-total Transmission Maintenance	SUM L17 to L24	$38,362	$38,362	
26							
27			**TOTAL TRANSMISSION EXPENSE**	L15 + L25	$269,116	$82,208	$186,907
28							
29	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation & Supervision	580.0	$1,271		$1,271
30			Load Dispatching	581.0			
31			Station Expenses	582.0	816		816
32			Overhead Lines Expenses	583.0	17,513		17,513
33			Underground Lines Expense	584.0	14,687		14,687
34			Meter Expenses	586.0	7,801		7,801
35			Customer Installations Expense	587.0	14,386		14,386
36			Miscellaneous Expense	588.0	90,014		90,014
37			Rents	589.0	3,658		3,658
38			Sub-total Distribution Operations	SUM L29 to L37	$150,143		$150,143
39							
40		Distribution Maintenance	Maintenance of Structures	591.0	6,622		6,622
41			Maintenance of Station Equipment	592.0	18,529		18,529
42			Maintenance of Overhead Lines	593.0	189,290		189,290
43			Maintenance of Underground Lines	594.0	38,602		38,602
44			Maintenance of Line Transformers	595.0	2,378		2,378
45			Maintenance of Street Lighting & Signal Systems	596.0	1,990		1,990
46			Maintenance of Misc. Distribution	598.0	20,293		20,293

Line No.	Category	Description	Account	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
47			Sub-total Distribution Maintenance	SUM L40 to L46	$277,703		$277,703
48							
49			**TOTAL DISTRIBUTION EXPENSE**	L38 + L47	$427,846		$427,846
50							
51	**CUSTOMER ACCOUNTS**	Customer Accounts	Supervision	901.0			
52			Meter Reading	902.0	976		976
53			Customer Records and Collection	903.0	105,441		105,441
54			Uncollectible Accounts	904.0	38,095		38,095
55			Miscellaneous Customer Accounts	905.0	3,295		3,295
56			**TOTAL CUSTOMER ACCOUNTS**	SUM L51 to L55	$147,808		$147,808
57							
58	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$101,517		$101,517
59			Informational & Instructional	909.0	1,407		1,407
60			Miscellaneous Customer & Informational	910.0	992		992
61			**TOTAL CUSTOMER SERVICE & INFORMATION**	SUM L58 to L60	$103,916		$103,916
62							
63	**SALES**	Sales Expense	Demonstrating & Selling	912.0	$414		$414
64			Miscellaneous Sales	916.0			
65			**TOTAL SALES EXPENSE**	SUM L63 to L64	$414		$414
66							
67	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$22,337	($7,552)	$29,889
68			Office Supplies and Expenses	921.0	4,628	1,063	3,566
69			Administrative Expenses Transferred-Credit	922.0			
70			Outside Service Employed	923.0	98,279	10,130	88,149
71			Property Insurance	924.0	833	91	741
72			Injuries & Damages	925.0	12,396	75	12,322
73			Employee Pensions and Benefits	926.0	26,786	2,043	24,743
74			Regulatory Commission Expenses	928.0	9,839	288	9,551
75			Duplicate Charges-Credit	929.0	(1,634)	(542)	(1,092)
76			Miscellaneous General Expenses	930.2	3,134	607	2,527
77			Sub-total A&G Operations	SUM L67 to L76	$176,599	$6,204	$170,395
78							
79		A&G Maintenance	Maintenance of General Plant	935.0	9,183	946	8,237
80							
81			TOTAL ADMINISTRATION & GENERAL	L77 + L79	$185,781	$7,150	$178,632
82							
83			**TOTAL O&M EXPENSE**	L2+L27+L49+L56+L61+L65+L81	$2,138,595	$89,358	$2,049,237
84							
85			TOTAL OPERATIONS EXPENSE		$1,822,531	$50,996	$1,771,534
86			TOTAL MAINTENANCE EXPENSE		316,064	38,362	277,703
87			**TOTAL O&M EXPENSE**	L85 + L86	**$2,138,595**	**$89,358**	**$2,049,237**

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
1	**Distribution**	**A&G Operations**	Administrative and General Salaries	920.0	$29,889	0.0000%		$29,889
2			Office Supplies and Expenses	921.0	3,545	0.0000%		3,545
3			Administrative Expenses Transferred-Credit	922.0		0.0000%		
4			Outside Service Employed	923.0	88,149	0.0000%		88,149
5			Property Insurance	924.0	741	0.0000%		741
6			Injuries and Damages	925.0	12,322	0.0000%		12,322
7			Employee Pensions and Benefits	926.0	24,743	0.0000%		24,743
8			Regulatory Commission Expenses	928.0	9,551	0.0000%		9,551
9			Duplicate Charges-Credit	929.0	(1,092)	0.0000%		(1,092)
10			Miscellaneous General Expenses	930.2	2,527	0.0000%		2,527
11			Sub-total A&G Operations - Distribution	SUM L1 to L10	$170,373			$170,373
12								
13		**A&G Maintenance**	Maintenance of General Plant	935.0	$8,237	0.0000%		$8,237
14			**ADMINISTRATION & GENERAL - DISTRIBUTION**	L11 + L13	$178,610			$178,610
15								
16	**Transmission**	**A&G Operations**	Administrative and General Salaries	920.0	($7,552)	100.0000%	($7,552)	
17			Office Supplies and Expenses	921.0	1,060	100.0000%	1,060	
18			Administrative Expenses Transferred-Credit	922.0		100.0000%		
19			Outside Service Employed	923.0	10,130	100.0000%	10,130	
20			Property Insurance	924.0	91	100.0000%	91	
21			Injuries and Damages	925.0	75	100.0000%	75	
22			Employee Pensions and Benefits	926.0	2,043	100.0000%	2,043	
23			Regulatory Commission Expenses	928.0	288	100.0000%	288	
24			Duplicate Charges-Credit	929.0	(542)	100.0000%	(542)	
25			Miscellaneous General Expenses	930.2	607	100.0000%	607	
26			Sub-total A&G Operations - Transmission	SUM L16 to L25	$6,201		$6,201	
27								
28		**A&G Maintenance**	Maintenance of General Plant	935.0	$946	100.0000%	$946	
29			**ADMINISTRATION & GENERAL - TRANSMISSION**	L26 + L28	$7,147		$7,147	
30								

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Percent to Non-Jurisdiction	(3) Non-Jurisdictional	(4) Jurisdictional
31	**General**	**A&G Operations**	Administrative and General Salaries	920.0		12.3730%		
32			Office Supplies and Expenses	921.0	24	12.3730%	3	21
33			Administrative Expenses Transferred-Credit	922.0		12.3730%		
34			Outside Service Employed	923.0		12.3730%		
35			Property Insurance	924.0		12.3730%		
36			Injuries and Damages	925.0		12.3730%		
37			Employee Pensions and Benefits	926.0		12.3730%		
38			Regulatory Commission Expenses	928.0		12.3730%		
39			Duplicate Charges-Credit	929.0		12.3730%		
40			Miscellaneous General Expenses	930.2	0	12.3730%	0	0
41			Sub-total A&G Operations - General	SUM L31 to L40	$25		$3	$22
42								
43		**A&G Maintenance**	Maintenance of General Plant	935.0	$0	12.3730%	$0	$0
44			**ADMINISTRATION & GENERAL - GENERAL**	L41 + L43	$25		$3	$22
45								
46	**TOTAL**	**A&G Operations**	Administrative and General Salaries	920.0	$22,337		($7,552)	$29,889
47			Office Supplies and Expenses	921.0	4,628		1,063	3,566
48			Administrative Expenses Transferred-Credit	922.0				
49			Outside Service Employed	923.0	98,279		10,130	88,149
50			Property Insurance	924.0	833		91	741
51			Injuries & Damages	925.0	12,396		75	12,322
52			Employee Pensions and Benefits	926.0	26,786		2,043	24,743
53			Regulatory Commission Expenses	928.0	9,839		288	9,551
54			Duplicate Charges-Credit	929.0	(1,634)		(542)	(1,092)
55			Miscellaneous General Expenses	930.2	3,134		607	2,527
56			Sub-total A&G Operations - TOTAL	SUM L46 to L55	$176,599		$6,204	$170,395
57								
58		**A&G Maintenance**	Maintenance of General Plant	935.0	$9,183		$946	$8,237
59			**ADMINISTRATION & GENERAL - TOTAL**	L56 + L58	$185,781		$7,150	$178,632

Line No.	Description	Percentage	(1) Total	(2) Transmission Elimination	(3) Distribution
1	Public Utility Real Tax (PURTA) Total Expense	17.825%	$6,924	($1,234)	$5,690
2	Use Tax Accrued	17.825%	2,443	(435)	2,007
3	Real Estate Tax Accrued	17.825%	5,988	(1,067)	4,920
4	Miscellaneous TOTI	12.373%			
5	Payroll Tax Accrued	12.373%	14,402	(1,782)	12,620
6	Gross Receipt Tax		172,280		172,280
7	**Total**		**$202,036**	**($4,519)**	**$197,517**

Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effectivel nterest Rate	Average Weighted Cost Rate	Annualized Cost
		(1)		(2)	(3)	(4)	(5)	(6)
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $350 - 3.15% - Due 10-15-2025						
2								
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		$75,000		6.00%		
4					1.14%		0.07%	
5		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
6					4.56%		0.28%	
7		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
8					2.66%		0.15%	
9		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
10					3.80%		0.19%	
11		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.21%		
12					4.56%		0.19%	
13		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
14					4.94%		0.19%	
15		PECO - FMB - $650 - 3.90% - Due 3-1-2048		650,000		4.08%		
16					9.87%		0.40%	
17		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
18					4.94%		0.15%	
19		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
20					5.32%		0.15%	
21		PECO - FMB - $375 - 3.05% - Due 3-15-2051		375,000		3.11%		
22					5.70%		0.18%	
23		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.90%		
24					5.70%		0.17%	
25		PECO - FMB - $350 - 4.60% - Due 5-15-2052		350,000		4.71%		
26					5.32%		0.25%	
27		PECO - FMB - $425 - 4.375% - Due 8-15-2052		425,000		4.46%		
28					6.46%		0.29%	
29		PECO - FMB - $575 - 4.90% - Due 6-15-2033		575,000		5.03%		
30					8.73%		0.44%	
31		PECO - FMB - $575 - 5.46% - Due 9-1-54		575,000		5.53%		
32					8.73%		0.48%	
33		PECO - FMB - $975 - 5.46% - Due 9-1-55		975,000		5.53%		
34					14.81%		0.82%	
35								
36		Sub-total Mortgage Bonds	SUM L1 to L35	$6,400,000	97.20%		4.40%	
37								
38	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.46%		
39					1.22%		0.09%	
40		PECO - TOPRS - $0.8 - Var (6.75%) - Due 4-6-2028		805		6.75%		
41					0.01%			
42		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
43					1.57%		0.09%	
44								
45		Sub-total Capital Securities	SUM L38 to L43	$184,419	2.80%		0.18%	
46								
47		Total Long-Term Debt	L36 + L45	$6,584,419	100.00%		4.58%	
48								
49		Adjustments for Tenders & Calls		(521)				
50								
51		Net Long-Term Debt	L47 + L49	$6,583,898				
52								
53		Annualized Cost		301,566				
54								
55		Adjustment for Tenders & Calls Reacquired		68				
56								
57		**Total**	L53 + L55	$301,634				4.58%

	(1)	(2)	(3)	(4)
Line No.	Description	Capitalization	Capitalization Ratio	Embedded Cost	Return %
1					
2	Long-Term Debt	$6,583,898	46.60%	4.58%	2.13%
3					
4	Common Equity	$7,545,824	53.40%	10.95%	5.85%
5					
6	Total	$14,129,722	100.00%		7.98%

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		(1)	(2)	(3)	(4)
Line No.	Description	Reference	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	Utility Plant	C-2	$13,491,056	$2,248,150	$11,242,906
2	Accumulated Depreciation	C-3	2,913,861	660,134	2,253,728
3	Common Plant	C-8	555,965		555,965
4	**Net Plant in Service**	L1 - L2 + L3	$11,133,160	$1,588,017	$9,545,143
5					
6	Working Capital	C-4	$214,819		$214,819
7	Accumulated Deferred Income Taxes	C-6	(596,644)		(596,644)
8	Customer Deposits	C-7	(57,291)		(57,291)
9	Customer Advances for Construction	C-9	(2,889)		(2,889)
10	Material & Supplies	C-11	30,350		30,350
11	ADIT - Reg Liability	C-12	(277,875)		(277,875)
12	**Total Measures of Value**	SUM L4 to L11	$10,443,630	$1,588,017	$8,855,613

Line No.	Category	Account	Reference	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents		$163	$20	$143
3		E303 - Misc Intangible Plant		159,584	14,388	145,196
4		Sub-total Intangible Plant	SUM L1 to L3	$159,746	$14,408	$145,339
5						
6	**Transmission Plant**	E350 - Land and Land Rights		$75,731	$75,731	
7		E352 - Structures and Improvements		113,192	113,192	
8		E353 - Station Equipment		1,097,896	1,097,896	
9		E354 - Towers and Fixtures		294,157	294,157	
10		E355 - Poles and Fixtures		36,485	36,485	
11		E356 - Overhead Conductors, Devices		357,410	357,410	
12		E357 - Underground Conduit		68,327	68,327	
13		E358 - Undergrnd Conductors, Devices		147,404	147,404	
14		E359 - Roads and Trails		2,813	2,813	
15		E359.1 - ARO Costs Transmission Plt		502	502	
16		Sub-total Transmission Plant	SUM L6 to L15	$2,193,919	$2,193,919	
17						
18	**Distribution Plant**	E360 - Land and Land Rights		$54,159		$54,159
19		E361 - Structures and Improvements		255,582		255,582
20		E362 - Station Equipment		1,404,950		1,404,950
21		E364 - Poles, Towers and Fixtures		1,492,502		1,492,502
22		E365 - Overhead Conductors, Devices		2,382,803		2,382,803
23		E366 - Underground Conduit		1,045,522		1,045,522
24		E367 - Undergrnd Conductors, Devices		2,284,412		2,284,412
25		E368 - Line Transformers		930,272		930,272
26		E369 - Services		503,567		503,567
27		E370 - Meters		369,190		369,190
28		E371 - Installs on Customer Premiss		13,772		13,772
29		E373 - Street Lighting, Signal Systems		76,447		76,447
30		E374 - ARO Costs Distribution Plant		2,353		2,353
31		Sub-total Distribution Plant	SUM L18 to L30	$10,815,532		$10,815,532
32						
33	**General Plant**	E389 - Land and Land Rights		$1,063	$132	$932
34		E390 - Structures and Improvements		50,977	6,307	44,670
35		E391 - Office Furniture, Equipment		21,610	2,674	18,937
36		E392 - Transportation Equipment				
37		E393 - Stores Equipment		44	5	38
38		E394 - Tools, Shop, Garage Equipment		56,585	7,001	49,583
39		E395 - Laboratory Equipment		150	19	132
40		E396 - Power Operated Equipment				
41		E397 - Communication Equipment		188,797	23,360	165,437
42		E398 - Miscellaneous Equipment		716	89	627
43		E399 - Other Tangible Property				
44		E399.1 - ARO Costs General Plant		1,916	237	1,679
45		Sub-total General Plant	SUM L33 to L44	$321,859	$39,824	$282,035
46						
47		**Total**	L4+L16+L31+L45	**$13,491,056**	**$2,248,150**	**$11,242,906**

(1)

Line No.	Category	Account	Additions to Plant
1	**Intangible Plant**	E303 - Misc Intangible Plant	$39,375
2		Sub-total Intangible Plant	$39,375
3			
4	**Transmission Plant**	E350 - Land and Land Rights	($0)
5		E352 - Structures and Improvements	4,224
6		E353 - Station Equipment	33,531
7		E354 - Towers and Fixtures	1,047
8		E355 - Poles and Fixtures	2,457
9		E356 - Overhead Conductors, Devices	28,138
10		E357 - Underground Conduit	9,172
11		E358 - Undergrnd Conductors, Devics	7,317
12		E359 - Roads and Trails	68
13		Sub-total Transmission Plant	$85,954
14			
15	**Distribution Plant**	E361 - Structures and Improvements	$24,160
16		E362 - Station Equipment	82,485
17		E364 - Poles, Towers and Fixtures	187,472
18		E365 - Overhead Conductors, Devices	234,850
19		E366 - Underground Conduit	141,528
20		E367 - Undergrnd Conductors, Devics	260,419
21		E368 - Line Transformers	94,706
22		E369 - Services	18,305
23		E370 - Meters	11,333
24		E373 - Street Lighting,Signal Systm	5,828
25		Sub-total Distribution Plant	$1,061,088
26			
27	**General Plant**	E390 - Structures and Improvements	$94
28		E391 - Office Furniture, Equipment	2,962
29		E394 - Tools, Shop, Garage Equipmnt	3,084
30		E397 - Communication Equipment	5,317
31		E398 - Miscellaneous Equipment	38
32		Sub-total General Plant	$11,495
33			
34		**Total**	**$1,197,911**

(1)

Line No.	Category	Account	Plant Retirements
1	**Intangible Plant**	E303 - Misc Intangible Plant	($37,729)
2		Sub-total Intangible Plant	($37,729)
3			
4	**Transmission Plant**	E352 - Structures and Improvements	($73)
5		E353 - Station Equipment	(3,590)
6		E354 - Towers and Fixtures	(103)
7		E355 - Poles and Fixtures	(0)
8		E356 - Overhead Conductors, Devices	(72)
9		E357 - Underground Conduit	(7)
10		E358 - Undergrnd Conductors, Devics	(38)
11		E359.1 - ARO Costs Transmission Plt	(1)
12		Sub-total Transmission Plant	($3,884)
13			
14	**Distribution Plant**	E361 - Structures and Improvements	($669)
15		E362 - Station Equipment	(3,172)
16		E364 - Poles, Towers and Fixtures	(20,980)
17		E365 - Overhead Conductors, Devices	(16,652)
18		E366 - Underground Conduit	(835)
19		E367 - Undergrnd Conductors, Devics	(17,858)
20		E368 - Line Transformers	(16,468)
21		E369 - Services	(198)
22		E370 - Meters	(196)
23		E373 - Street Lighting,Signal Systm	(715)
24		E374 - ARO Costs Distribution Plt	(170)
25		Sub-total Distribution Plant	($77,913)
26			
27	**General Plant**	E390 - Structures and Improvements	($70)
28		E391 - Office Furniture, Equipment	(7,198)
29		E393 - Stores Equipment	(1)
30		E394 - Tools, Shop, Garage Equipmnt	(1,060)
31		E395 - Laboratory Equipment	(52)
32		E397 - Communication Equipment	(2,098)
33		E398 - Miscellaneous Equipment	(25)
34		E399.1 - ARO Costs General Plt	(21)
35		Sub-total General Plant	($10,525)
36			
37		**Total**	**($130,050)**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FPFTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	E301 - Organization Costs						
2								
3		E302 - Franchises and Consents	$163	100.00%	$163	87.63%	$143	$20
4			$163		$163		$143	$20
5								
6		E303 - Misc Intangible Plant	$159,584	100.00%	$159,584	90.98%	$145,196	$14,388
7			$159,584		$159,584		$145,196	$14,388
8								
9		Sub-total Intangible Plant	$159,746		$159,746		$145,339	$14,408
10								
11	**Transmission Plant**	E350 - Land and Land Rights	$75,731	100.00%	$75,731			$75,731
12			$75,731		$75,731			$75,731
13								
14		E352 - Structures and Improvements	113,192	100.00%	113,192			113,192
15			113,192		113,192			113,192
16								
17		E353 - Station Equipment	1,097,896	100.00%	1,097,896			1,097,896
18			1,097,896		1,097,896			1,097,896
19								
20		E354 - Towers and Fixtures	294,157	100.00%	294,157			294,157
21			294,157		294,157			294,157
22								
23		E355 - Poles and Fixtures	36,485	100.00%	36,485			36,485
24			36,485		36,485			36,485
25								
26		E356 - Overhead Conductors, Devices	357,410	100.00%	357,410			357,410
27			357,410		357,410			357,410
28								
29		E357 - Underground Conduit	68,327	100.00%	68,327			68,327
30			68,327		68,327			68,327
31								
32		E358 - Undergrnd Conductors, Devices	147,404	100.00%	147,404			147,404
33			147,404		147,404			147,404
34								
35		E359 - Roads and Trails	2,813	100.00%	2,813			2,813
36			2,813		2,813			2,813
37								
38		E359.1 - ARO Costs Transmission Plt	502	100.00%	502			502
39			502		502			502
40								
41		Sub-total Transmission Plant	$2,193,919		$2,193,919			$2,193,919
42								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FPFTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
43	**Distribution Plant**	E360 - Land and Land Rights	$54,159	100.00%	$54,159	100.00%	$54,159	
44			$54,159		$54,159		$54,159	
45								
46		E361 - Structures and Improvements	255,582	100.00%	255,582	100.00%	255,582	
47			255,582		255,582		255,582	
48								
49		E362 - Station Equipment	1,404,950	100.00%	1,404,950	100.00%	1,404,950	
50			1,404,950		1,404,950		1,404,950	
51								
52		E364 - Poles, Towers and Fixtures	1,492,502	100.00%	1,492,502	100.00%	1,492,502	
53			1,492,502		1,492,502		1,492,502	
54								
55		E365 - Overhead Conductors, Devices	2,382,803	100.00%	2,382,803	100.00%	2,382,803	
56			2,382,803		2,382,803		2,382,803	
57								
58		E366 - Underground Conduit	1,045,522	100.00%	1,045,522	100.00%	1,045,522	
59			1,045,522		1,045,522		1,045,522	
60								
61		E367 - Undergrnd Conductors, Devices	2,284,412	100.00%	2,284,412	100.00%	2,284,412	
62			2,284,412		2,284,412		2,284,412	
63								
64		E368 - Line Transformers	930,272	100.00%	930,272	100.00%	930,272	
65			930,272		930,272		930,272	
66								
67		E369 - Services	503,567	100.00%	503,567	100.00%	503,567	
68			503,567		503,567		503,567	
69								
70		E370 - Meters	369,190	100.00%	369,190	100.00%	369,190	
71			369,190		369,190		369,190	
72								
73		E371 - Installs on Customer Premiss	13,772	100.00%	13,772	100.00%	13,772	
74			13,772		13,772		13,772	
75								
76		E373 - Street Lighting, Signal Systems	76,447	100.00%	76,447	100.00%	76,447	
77			76,447		76,447		76,447	
78								
79		E374 - ARO Costs Distribution Plant	2,353	100.00%	2,353	100.00%	2,353	
80		Electric Nonrecoverable 100%						
81			2,353		2,353		2,353	
82								
83		Sub-total Distribution Plant	$10,815,532		$10,815,532		$10,815,532	
84								

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FPFTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
85	**General Plant**	E389 - Land and Land Rights	$1,063	100.00%	$1,063	87.63%	$932	$132
86			$1,063		$1,063		$932	$132
87								
88		E390 - Structures and Improvements	50,977	100.00%	50,977	87.63%	44,670	6,307
89			50,977		50,977		44,670	6,307
90								
91		E391 - Office Furniture, Equipment	21,610	100.00%	21,610	87.63%	18,937	2,674
92			21,610		21,610		18,937	2,674
93								
94		E393 - Stores Equipment	44	100.00%	44	87.63%	38	5
95			44		44		38	5
96								
97		E394 - Tools, Shop, Garage Equipment	56,585	100.00%	56,585	87.63%	49,583	7,001
98			56,585		56,585		49,583	7,001
99								
100		E395 - Laboratory Equipment	150	100.00%	150	87.63%	132	19
101			150		150		132	19
102								
103		E397 - Communication Equipment	188,797	100.00%	188,797	87.63%	165,437	23,360
104			188,797		188,797		165,437	23,360
105								
106		E398 - Miscellaneous Equipment	716	100.00%	716	87.63%	627	89
107			716		716		627	89
108								
109		E399.1 - ARO Costs General Plant	1,916	100.00%	1,916	87.63%	1,679	237
110			1,916		1,916		1,679	237
111								
112		Sub-total General Plant	$321,859		$321,859		$282,035	$39,824
113								
114								
115		**Total**	**$13,491,056**		**$13,491,056**		**$11,242,906**	**$2,248,150**

Line No.	Category	Account	Reference	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Intangible Plant**	E301 - Organization Costs				
2		E302 - Franchises and Consents				
3		E303 - Misc Intangible Plant		$59,245	$3,490	$55,755
4		Sub-total Intangible Plant	SUM L1 to L3	$59,245	$3,490	$55,755
5						
6	**Transmission Plant**	E350 - Land and Land Rights		($0)	($0)	
7		E352 - Structures and Improvements		31,474	31,474	
8		E353 - Station Equipment		265,819	265,819	
9		E354 - Towers and Fixtures		179,707	179,707	
10		E355 - Poles and Fixtures		4,503	4,503	
11		E356 - Overhead Conductors, Devices		100,684	100,684	
12		E357 - Underground Conduit		3,242	3,242	
13		E358 - Undergrnd Conductors, Devices		50,614	50,614	
14		E359 - Roads and Trails		2,247	2,247	
15		E359.1 - ARO Costs Transmission Plt		122	122	
16		Sub-total Transmission Plant	SUM L6 to L15	$638,410	$638,410	
17						
18	**Distribution Plant**	E360 - Land and Land Rights		$310		310
19		E361 - Structures and Improvements		52,846		$52,846
20		E362 - Station Equipment		533,251		533,251
21		E364 - Poles, Towers and Fixtures		82,042		82,042
22		E365 - Overhead Conductors, Devices		313,680		313,680
23		E366 - Underground Conduit		199,133		199,133
24		E367 - Undergrnd Conductors, Devices		206,658		206,658
25		E368 - Line Transformers		182,504		182,504
26		E369 - Services		213,095		213,095
27		E370 - Meters		235,464		235,464
28		E371 - Installs on Customer Premises		11,799		11,799
29		E373 - Street Lighting, Signal Systems		36,153		36,153
30		E374 - ARO Costs Distribution Plant		1,907		1,907
31		Sub-total Distribution Plant	SUM L18 to L30	$2,068,842		$2,068,842
32						
33	**General Plant**	E389 - Land and Land Rights				
34		E390 - Structures and Improvements		$18,173	$2,249	$15,924
35		E391 - Office Furniture, Equipment		12,790	1,582	11,207
36		E392 - Transportation Equipment				
37		E393 - Stores Equipment		32	4	28
38		E394 - Tools, Shop, Garage Equipmnt		25,759	3,187	22,572
39		E395 - Laboratory Equipment		142	18	125
40		E396 - Power Operated Equipment				
41		E397 - Communication Equipment		88,827	10,991	77,837
42		E398 - Miscellaneous Equipment		(238)	(29)	(208)
43		E399 - Other Tangible Property				
44		E399.1 - ARO Costs General Plt		1,879	232	1,646
45		Sub-total General Plant	SUM L33 to L44	$147,364	$18,234	$129,131
46						
47		**Total**	L4+L16+L31+L45	**$2,913,861**	**$660,134**	**$2,253,728**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FPFTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	E302 - Franchises and Consents						
2								
3								
4		E303 - Misc Intangible Plant	$59,245	100.00%	$59,245	94.11%	55,755	$3,490
5			$59,245	100.00%	$59,245	94.11%	$55,755	$3,490
6								
7		Sub-total Intangible Plant	$59,245		$59,245		$55,755	$3,490
8								
9	**Transmission Plant**	E350 - Land and Land Rights	($0)	100.00%	($0)			($0)
10			($0)		($0)			($0)
11								
12		E352 - Structures and Improvements	31,474	100.00%	31,474			31,474
13			31,474		31,474			31,474
14								
15		E353 - Station Equipment	265,819	100.00%	265,819			265,819
16			265,819		265,819			265,819
17								
18		E354 - Towers and Fixtures	179,707	100.00%	179,707			179,707
19			179,707		179,707			179,707
20								
21		E355 - Poles and Fixtures	4,503	100.00%	4,503			4,503
22			4,503		4,503			4,503
23								
24		E356 - Overhead Conductors, Devices	100,684	100.00%	100,684			100,684
25			100,684		100,684			100,684
26								
27		E357 - Underground Conduit	3,242	100.00%	3,242			3,242
28			3,242		3,242			3,242
29								
30		E358 - Undergrnd Conductors, Devices	50,614	100.00%	50,614			50,614
31			50,614		50,614			50,614
32								
33		E359 - Roads and Trails	2,247	100.00%	2,247			2,247
34			2,247		2,247			2,247
35								
36		E359.1 - ARO Costs Transmission Plt	122	100.00%	122			122
37			122		122			122
38								
39		Sub-total Transmission Plant	$638,410		$638,410			$638,410
40								

Line No.	Description	Account	(1) FPFTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
41	**Distribution Plant**	E360 - Land and Land Rights	310	100.00%	310	100.00%	310	
42			310		310		310	
43								
44		E361 - Structures and Improvements	$52,846	100.00%	$52,846	100.00%	$52,846	
45			$52,846		$52,846		$52,846	
46								
47		E362 - Station Equipment	533,251	100.00%	533,251	100.00%	533,251	
48			533,251		533,251		533,251	
49								
50		E364 - Poles, Towers and Fixtures	82,042	100.00%	82,042	100.00%	82,042	
51			82,042		82,042		82,042	
52								
53		E365 - Overhead Conductors, Devices	313,680	100.00%	313,680	100.00%	313,680	
54			313,680		313,680		313,680	
55								
56		E366 - Underground Conduit	199,133	100.00%	199,133	100.00%	199,133	
57			199,133		199,133		199,133	
58								
59		E367 - Undergrnd Conductors, Devices	206,658	100.00%	206,658	100.00%	206,658	
60			206,658		206,658		206,658	
61								
62		E368 - Line Transformers	182,504	100.00%	182,504	100.00%	182,504	
63			182,504		182,504		182,504	
64								
65		E369 - Services	213,095	100.00%	213,095	100.00%	213,095	
66			213,095		213,095		213,095	
67								
68		E370 - Meters	235,464	100.00%	235,464	100.00%	235,464	
69			235,464		235,464		235,464	
70								
71		E371 - Installs on Customer Premises	11,799	100.00%	11,799	100.00%	11,799	
72			11,799		11,799		11,799	
73								
74		E373 - Street Lighting, Signal Systems	36,153	100.00%	36,153	100.00%	36,153	
75			36,153		36,153		36,153	
76								
77		E374 - ARO Costs Distribution Plant	1,907	100.00%	1,907	100.00%	1,907	
78								
79			1,907		1,907		1,907	
80								
81		Sub-total Distribution Plant	$2,068,842		$2,068,842		$2,068,842	
82								

Line No.	Description	Account	(1) FPFTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
83	**General Plant**	E389 - Land and Land Rights						
84								
85								
86		E390 - Structures and Improvements	$18,173	100.00%	$18,173	87.63%	$15,924	$2,249
87			$18,173		$18,173		$15,924	$2,249
88								
89		E391 - Office Furniture, Equipment	12,790	100.00%	12,790	87.63%	11,207	1,582
90			12,790		12,790		11,207	1,582
91								
92		E393 - Stores Equipment	32	100.00%	32	87.63%	28	4
93			32		32		28	4
94								
95		E394 - Tools, Shop, Garage Equipmnt	25,759	100.00%	25,759	87.63%	22,572	3,187
96			25,759		25,759		22,572	3,187
97								
98		E395 - Laboratory Equipment	142	100.00%	142	87.63%	125	18
99			142		142		125	18
100								
101		E397 - Communication Equipment	88,827	100.00%	88,827	87.63%	77,837	10,991
102			88,827		88,827		77,837	10,991
103								
104		E398 - Miscellaneous Equipment	(238)	100.00%	(238)	87.63%	(208)	(29)
105			(238)		(238)		(208)	(29)
106								
107		E399.1 - ARO Costs General Plt	1,879	100.00%	1,879	87.63%	1,646	232
108			1,879		1,879		1,646	232
109								
110		Sub-total General Plant	$147,364		$147,364		$129,131	$18,234
111								
112		**Total**	**$2,913,861**		**$2,913,861**		**$2,253,728**	**$660,134**

Line No.	Category	Account	(1) Reference	(2) FPFTY Amount
1	**Electric - Intangible Plant**	E303 - Misc Intangible Plant		($0)
2		Sub-total Electric - Intangible Plant		($0)
3				
4	**Electric - Transmission**	E350 - Land and Land Rights		$0
5		E352 - Structures and Improvements		123
6		E353 - Station Equipment		2,704
7		E354 - Towers and Fixtures		177
8		E355 - Poles and Fixtures		76
9		E356 - Overhead Conductors, Devices		1,462
10		E357 - Underground Conduit		850
11		E358 - Undergrnd Conductors, Devics		1,172
12		E359 - Roads and Trails		4
13		Sub-total Electric - Transmission	SUM L4 to L12	$6,569
14				
15	**Electric - Distribution**	E361 - Structures and Improvements		$1,110
16		E362 - Station Equipment		5,746
17		E364 - Poles, Towers and Fixtures		16,669
18		E365 - Overhead Conductors, Devices		19,073
19		E366 - Underground Conduit		4,267
20		E367 - Undergrnd Conductors, Devics		20,169
21		E368 - Line Transformers		897
22		E369 - Services		708
23		E370 - Meters		207
24		E373 - Street Lighting, Signal Systems		114
25		Sub-total Electric - Distribution	SUM L15 to L24	$68,960
26				
27	**Electric - General Plant**	E390 - Structures and Improvements		$95
28		E391 - Office Furniture, Equipment		60
29		E394 - Tools, Shop, Garage Equipmnt		14
30		E397 - Communication Equipment		556
31		E398 - Miscellaneous Equipment		93
32		Sub-total Electric - General Plant	SUM L27 to L31	$818
33				
34		**Total**	Lines 2+13+25+32	**$76,347**

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	FPFTY Expenses	(Lead)/Lag Days	Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			51.95	
4					
5	Expense Lag Days				
6	Payroll (Dist Only)		$173,658	13.58	$2,358,858
7	Pension Expense		3,216	(167.00)	(537,107)
8	Commodity Purchased - [A]		995,523	35.71	35,548,467
9	Commodity Purchased - [B]		8,190	12.50	102,374
10	PJM Transmission Purchased - By-passable		91,766	12.50	1,147,070
11	PJM Transmission Purchased - Non By-passable		95,142	12.50	1,189,272
12	Other Expenses		589,752	40.07	23,632,573
13	Sub-Total O&M	SUM L6 to L12	$1,957,247		$63,441,506
14					
15	Payment to Suppliers		$1,082,504	37.88	$41,001,678
16					
17	Total O&M and POR Payments	L13 + L15	$3,039,751		$104,443,185
18					
19	O&M Expense / POR Payment Lag Days			34.36	
20					
21	Net Lead/(Lag) Days	L3 - L19		17.59	
22					
23	Days in Current Year			365	
24					
25	Operating Expenses Per Day		$8,328		
26					
27	Working Capital for O&M Expense		$146,494		
28					
29	Average Prepayments		$8,636		
30	Accrued Taxes		$80,040		
31	Interest Payments		($20,350)		
32					
33	**Total Working Capital Requirement**	SUM L27 to L31	**$214,819**		
34					
35	Pro Forma O&M Expense		$2,004,819		
36	Uncollectible Expense		47,573		
37	Pro Forma Cash O&M Expense	L35 - L36	$1,957,247		

Line No.	Description	Reference	(1) Accounts Receivable Balance End of Month	(2) Total Monthly Billing Revenue	(3) A/R Turnover	(4) Days Lag
1	Annual Number of Days					365
2						
3	December		$402,842			
4	January		453,446	$378,637		
5	February		445,195	329,190		
6	March		411,718	303,032		
7	April		408,197	278,953		
8	May		340,718	260,453		
9	June		347,805	288,753		
10	July		409,252	373,500		
11	August		386,093	404,999		
12	September		398,390	381,298		
13	October		308,580	293,722		
14	November		285,129	267,091		
15	December		341,788	320,380		
16						
17	Total	SUM L3 to L15	$4,939,151	$3,880,008		
18						
19	Average A/R Balance		13			
20						
21	Factor		$379,935	$3,880,008	10.21	35.74
22						
23	Collection Days Lag					35.74
24						
25	Billing and Revenue Recording Days Lag					1.00
26						
27	Billing Lag (Average Period)	365 / 12 * 0.5				15.21
28						
29	**Total Revenue Lag Days**	L23 + L25 + L27				**51.95**

Line No.	Category	Description	Reference	Payment Date	Mid-point of Service Period	Expense Amount	(Lead)/Lag Days	Dollar Days
			(1)	(2)	(3)	(4)	(5)	(6)
1	PAYROLL	Union & Non-Union Payroll				$167,922		
2		Paid Twice Per Month					13.58	
3		Weighted Payroll Dollar Value						$2,280,946
4								
5		**Payroll Lag**	SUM L1 to L3			$167,922	**13.58**	$2,280,946
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2025	7/1/2025	$3,300	(167.00)	($551,100)
12								
13		Sub-total	SUM L7 to L11			$3,300		($551,100)
14								
15		**Lag Days for Pension Payment**					(167.00)	
16								
17	PURCHASE COMMODITY COSTS	**Payment Lag - Contract Purchases**					**35.71**	
18		**Payment Lag - Spot Market/PJM Purchases**					**12.50**	
19		**Payment Lag - Payment to Suppliers**					**37.88**	
20								
21								
22	OTHER O & M EXPENSES	January				$16,812		$651,478
23		April				26,471		1,077,737
24		July				25,711		1,175,140
25		October				22,699		769,982
26								
27		**Lag Days for Other Expenses**	SUM L22 to L25			$91,693	**40.07**	$3,674,337

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			(1)	(2)	(3)	(4)
Line No.	Months	Description	Number of CDs	Cash Disbursements	Dollar-Days	Expense Lag Days
1	January	Total Disbursements for Month	19,206	$337,934		
2		Total Disbursements for Expenses	1,354	$16,812	$651,478	38.75
3						
4	April	Total Disbursements for Month	33,541	$241,401		
5		Total Disbursements for Expenses	2,115	$26,471	$1,077,737	40.71
6						
7	July	Total Disbursements for Month	29,010	$256,674	-	
8		Total Disbursements for Expenses	1,842	$25,711	$1,175,140	45.70
9						
10	October	Total Disbursements for Month	22,765	$232,356	-	
11		Total Disbursements for Expenses	1,978	$22,699	$769,982	33.92
12	**TOTAL FOUR TEST MONTHS**					
13						
14	**Total Test Month Expense Disbursement**		7,289	$91,693	$3,674,337	**40.07**

Line No.	Description	Description	Payment Date	Mid Point Date	Lead/(Lag) Payment Days	Total Payment Amount	Payment Percentage	Payment Amount	Weighted Dollar Days
			(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**FEDERAL INCOME TAX**	First Payment	4/15/2025	7/1/2025	77	$113,465	25.00%	$28,366	$2,184,201
2		Second Payment	6/16/2025	7/1/2025	15	113,465	25.00%	28,366	425,494
3		Third Payment	9/15/2025	7/1/2025	(76)	113,465	25.00%	28,366	(2,155,835)
4		Fourth Payment	12/15/2025	7/1/2025	(167)	113,465	25.00%	28,366	(4,737,164)
5		Sub-total FEDERAL INCOME TAX					100.00%	$113,465	($4,283,304)
6									
7	**STATE INCOME TAX**	First Payment	3/17/2025	7/1/2025	106	$12,681	25.00%	$3,170	$336,040
8		Second Payment	6/16/2025	7/1/2025	15	12,681	25.00%	3,170	47,553
9		Third Payment	9/15/2025	7/1/2025	(76)	12,681	25.00%	3,170	(240,934)
10		Fourth Payment	12/15/2025	7/1/2025	(167)	12,681	25.00%	3,170	(529,421)
11		Sub-total STATE INCOME TAX					100.00%	$12,681	($386,763)
12									
13	**PURTA**	First Payment	5/1/2025	7/1/2025	61	$5,690	100.00%	$5,690	$347,061
14		Subtotal PURTA					100.00%	$5,690	$347,061
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Sub-total PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/9/2025	7/1/2025	22	$4,920	100.00%	$4,920	$108,248
23		Second Payment							
24		Sub-total PA PROPERTY TAX					100.00%	$4,920	$108,248
25									
26	**GROSS RECEIPTS TAX**	First Payment	3/17/2025	7/1/2025	106	$166,666	100.00%	$166,666	$17,666,615
27		Sub-total GROSS RECEIPTS TAX					100.00%	$166,666	$17,666,615

Line No.	Description	(1) Total Payment Amount	(2) Weighted Dollar Days	(3) Payment Lead/(Lag) Days	(4) Revenue Lag Days	(5) Net Payment Lead/(Lag) Days	(6) Net Payment Lead/(Lag) Dollars Days	(7) Average Daily Amount for Working Capital
1	FEDERAL INCOME TAX	$113,465	($4,283,304)	(37.75)	51.95	14.20	$1,611,151	$4,414
2	STATE INCOME TAX	$12,681	($386,763)	(30.50)	51.95	21.45	$271,996	$745
3	PURTA	$5,690	$347,061	61.00	51.95	112.95	$642,630	$1,761
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$4,920	$108,248	22.00	51.95	73.95	$363,859	$997
6	GROSS RECEIPTS TAX	$166,666	$17,666,615	106.00	51.95	157.95	$26,324,847	$72,123

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Measures of Value at End of FPFTY		$8,855,613
2	Long-Term Debt Ratio		46.60%
3	Embedded Cost of Long-Term Debt		4.58%
4	Pro Forma Interest Expense	L1 * L2 * L3	$189,004
5	Days in Curent Year		365
6	Daily Amount	L4 / L5	$518
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days	C-4	51.95
9	Interest Payment Lag Days	L8 - L7	(39.30)
10	**Total Interest for Working Capital**	L6 * L9	**($20,350)**

Line No.	Description	Reference	(1) EPRI Dues	(2) EEI Dues	(3) EAP Membership Dues	(4) Prepaid Rents & Pole Attachments	(5) PUC Assessment Electric	(6) Land Leasing	(7) Maintenance	(8) IT License & Maintenance	(9) Business Support Systems	(10) VEBA Adjust	(11) Facilities Contracts	(12) IT License & Maintenance	(13) Fleet Activities	(14) IT License & Maintenance	(15) Customer Experience	(16) Postage	(17) Total Prepayment	(18)
1	December					$331	$3,893	$194		$32	$217	$2,394	$0	$96	$448	$71	$327	$1,247		
2	January			$573		788	3,032			(0)	469	2,394	(18)	88	465	51	285	816		
3	February			521		745	2,425			356	424	2,394	(35)	80	420	170	372	701		
4	March			469		558	1,819	188		324	333	3,157	157	88	420	254	305	662		
5	April		$304	417	$237	392	1,213		244	291	544	3,157	139	80	433	112	276	728		
6	May		203	365	138	212	606		195	259	453	3,157	122	72	428	159	243	731		
7	June		203	313	118	170	0	181	195	227	226	3,584	105	119	422	294	223	739		
8	July		203	261	99	641	5,155		195	204	467	3,584	87	111	441	562	277	760		
9	August		203	208	79	453	4,495		195	240	486	3,584	70	103	441	761	214	685		
10	September		101	156	59	624	5,779	175	195	201	513	3,775	52	136	399	623	146	664		
11	October		101	104	39	469	5,205		195	161	491	3,775	35	128	404	561	92	664		
12	November			52	20	284	4,630		195	405	363	3,775	17	120	438	500	59	712		
13	December			0		234	4,055	168	195	82	283	4,879	0	153	451	248	573	777		
14																				
15	Total	SUM L1 to L13	$1,319	$3,440	$788	$5,900	$42,307	$906	$1,804	$2,782	$5,270	$43,611	$731	$1,376	$5,610	$4,367	$3,392	$9,886		
16																				
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	67.41%	67.41%	67.41%	67.41%	74.50%	74.50%	74.50%		
18																				
19	Distribution Amount	L15 * L17	$1,319	$3,440	$788	$5,900	$42,307	$906	$1,804	$2,782	$5,270	$29,399	$493	$927	$3,782	$3,254	$2,527	$7,365		
20																				
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13		
22																				
23	Monthly Average	L19 / L21	$101	$265	$61	$454	$3,254	$70	$139	$214	$405	$2,261	$38	$71	$291	$250	$194	$567		
24																				
25	**Rate Case Amount**																			**$8,636**

Line No.	Description	(1) Midpoint of Prior Month Service Period to end of Month	(2) Payment Date Month after Service Period	(3) Additional Weekend or Holidays Extending Payment Date	(4) Lag Days	(5) Average
1	**Contract Purchases in FPFTY**					
2	January	15.50	19.00	1.00	35.50	
3	February	15.50	19.00	1.00	35.50	
4	March	14.00	19.00	1.00	34.00	
5	April	15.50	19.00	2.00	36.50	
6	May	15.00	19.00	1.00	35.00	
7	June	15.50	19.00	1.00	35.50	
8	July	15.00	19.00	2.00	36.00	
9	August	15.50	19.00	1.00	35.50	
10	September	15.50	19.00	3.00	37.50	
11	October	15.00	19.00	1.00	35.00	
12	November	15.50	19.00	1.00	35.50	
13	December	15.00	19.00	3.00	37.00	
14	**Payment Lag - Contract Purchases**					**35.71**
15						
16	**Spot Market Purchases in FPFTY and PJM Transmission Purchased**					
17		Service Period	Units	Service Period of Days	Lag Days	Total
18						
19	Service Period Weekly	Wed . to Tues.	Days	7.00		
20						
21	Days from Midpoint to End of Service				3.50	
22						
23	Payment Due on Friday of each Week				9.00	
24	**Payment Lag - Spot Market/PJM Purchases**					**12.50**
25						
26	**Payments to Suppliers**					
27		Payment Lag Days	Revenue Percentage	Weighted Lag Days	Lag Days	Total
28						
29	Residential	25.00	33%	8.34		
30	Nonresidential	20.00	67%	13.33		
31	Weighted Lag Days				21.67	
32						
33	Billing and Revenue Recording Days Lag				1.00	
34						
35	Billing Lag (Average Period)	365 / 12. * 0.5			15.21	
36						
37	Total POR Payment Lag Days	L31 + L33 + L35				**37.88**

Line No.	Test Year	Description	Reference	(1) Total Amount	(2) Percent to Utility	(3) Utility Amount	(4) Percent to Distribution	(5) Distribution Amount
1	**HTY**	ADIT - CIAC		($18,074)	100.00%	($18,074)	100.00%	($18,074)
2		ADIT - Common Plant		69,010	100.00%	69,010	63.22%	43,626
3		ADIT - Electric Common Plant		35,732	100.00%	35,732	82.17%	29,362
4		ADIT - Electric Distribution		619,210	100.00%	619,210	100.00%	619,210
5		ADIT - Corp. Alternative Minimum Tax		(60,332)	100.00%	(60,332)	100.00%	(60,332)
6		Sub-total	SUM L1 to L5	$645,546		$645,546		$613,793
7								
8	**FTY**	DIT - CIAC		($5,056)	100.00%	($5,056)	100.00%	($5,056)
9		DIT - Common Plant			100.00%		63.22%	
10		DIT - Electric Common Plant			100.00%		82.17%	
11		DIT - Electric Distribution		35,217	100.00%	35,217	100.00%	35,217
12		DIT - Corp. Alternative Minimum Tax		(48,211)	100.00%	(48,211)	100.00%	(48,211)
13		Sub-total	SUM L8 to L12	($18,050)		($18,050)		($18,050)
14								
15	**FPFTY**	DIT - CIAC		($5,035)	100.00%	($5,035)	100.00%	($5,035)
16		DIT - Common Plant			100.00%		63.22%	
17		DIT - Electric Common Plant			100.00%		82.17%	
18		DIT - Electric Distribution		27,673	100.00%	27,673	100.00%	27,673
19		DIT - Corp. Alternative Minimum Tax		(21,737)	100.00%	(21,737)	100.00%	(21,737)
20		Sub-total	SUM L15 to L19	$902		$902		$902
21								
22		**Total**	L6 + L13 + L20	**$628,397**		**$628,397**		**$596,644**

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Residential	Non-Residential	Total
1	December		$18,802	$31,587	$50,388
2	January		18,976	32,487	51,463
3	February		19,166	33,197	52,363
4	March		19,446	33,844	53,290
5	April		20,077	34,307	54,384
6	May		20,877	35,117	55,994
7	June		21,538	35,642	57,179
8	July		22,060	36,988	59,048
9	August		22,549	38,022	60,571
10	September		22,772	38,782	61,555
11	October		23,058	39,358	62,416
12	November		23,276	39,646	62,922
13	December		23,215	39,988	63,203
14					
15	Total	SUM L1 to L13	$275,812	$468,965	$744,777
16					
17	Average Monthly Balance	L15 / 13	$21,216	$36,074	$57,291
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$21,216
21	Small C&I				30,886
22	Large C&I				5,183
23	Other				5
24					
25	**Total**	SUM L20 to L23			**$57,291**

Line No.	Category	Account	Reference	FPFTY Amount	Allocated to Non Jurisdiction	Allocated to Jurisdiction
			(1)	(2)	(3)	(4)
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$221	$456
4						
5		E303 - Misc Intangible Plant		$337,580	$100,986	$236,594
6						
7		E389 - Land and Land Rights		$6,783	$2,211	$4,573
8						
9		E390 - Structures and Improvements		$432,164	$140,836	$291,328
10		E391 - Office Furniture, Equipment		82,575	26,910	55,665
11		E392 - Transportation Equipment		218,349	71,157	147,192
12		E393 - Stores Equipment		1,144	373	771
13		E394 - Tools, Shop, Garage Equipmnt		2,144	699	1,445
14		E396 - Power Operated Equipment		185	60	125
15		E397 - Communication Equipment		160,034	52,153	107,881
16		E398 - Miscellaneous Equipment		1,158	377	781
17		E399 - Other Tangible Property				
18		E399.1 - ARO Costs General Plant		803	262	541
19		Sub Total - General Plant	SUM L9 to L18	$898,556	$292,827	$605,729
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,243,596	$396,244	$847,352
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$156,223	$49,237	$106,986
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$70,406	$22,944	$47,462
31		E391 - Office Furniture, Equipment		35,258	11,490	23,768
32		E392 - Transportation Equipment		115,297	37,574	77,724
33		E393 - Stores Equipment		246	80	166
34		E394 - Tools, Shop, Garage Equipmnt		834	272	562
35		E396 - Power Operated Equipment		185	60	125
36		E397 - Communication Equipment		50,731	16,533	34,199
37		E398 - Miscellaneous Equipment		974	317	657
38		E399 - Other Tangible Property				
39		E399.1 - ARO Costs General Plant		(386)	(126)	(260)
40		Sub Total - General Plant	SUM L30 to L39	$273,546	$89,145	$184,401
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$429,769	$138,382	$291,387
42						
43		Net Common Plant	L20 - L41	$813,827	$257,861	$555,965
44						
45						
46		Common Plant in Service to Utility	L20	$1,243,596	$396,244	$847,352
47		Common Plant Accum Depreciation to Utility	L41	429,769	138,382	291,387
48		Net Common Plant to Utility	L46 - L47	$813,827	$257,861	$555,965

		(1)	(2)
Line No.	Description	Reference	Total
1	HTY 13-Month Average		
2	December		$2,662
3	January		2,509
4	February		2,978
5	March		3,239
6	April		3,066
7	May		2,900
8	June		2,423
9	July		2,393
10	August		2,049
11	September		3,859
12	October		3,861
13	November		2,764
14	December		2,855
15			
16	13-Month Total	SUM L2 to L14	$37,557
17			
18			
19	**Average Monthly Balance**	L16 / 13	**$2,889**

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Materials & Supplies	Undistributed Stores Expense	Total
1	HTY 13-Month Average				
2	December		$29,564	($0)	$29,564
3	January		30,031	(191)	29,840
4	February		28,319	(372)	27,947
5	March		26,573	(1,490)	25,083
6	April		26,183	(1,111)	25,072
7	May		26,568	(1,460)	25,108
8	June		27,575	(1,693)	25,882
9	July		28,584	(1,197)	27,387
10	August		33,678	(1,126)	32,553
11	September		34,598	(1,077)	33,522
12	October		34,602	(660)	33,943
13	November		36,708	(686)	36,023
14	December		39,019	0	39,019
15					
16	Total	SUM L2 to L14	$402,003	($11,061)	$390,942
17					
18	Distribution Expense Allocation Factor		100.00%	67.41%	
19					
20	Allocation to Distribution	L16 * L18	$402,003	($7,457)	
21					
22	**Average Monthly Balance**	L20 / 13	$30,923	($574)	**$30,350**

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - Distribution		$288,276	100.00%	$288,276	100.00%	$288,276
2		ADIT - CIAC			100.00%		100.00%	
3		Sub-total HTY	L1 + L2	288,276		288,276		288,276
4								
5	**FTY**	DIT - Distribution		($7,023)	100.00%	($7,023)	100.00%	($7,023)
6		DIT - CIAC			100.00%		100.00%	
7		Sub-total FTY	L5 + L6	($7,023)		($7,023)		($7,023)
8								
9	**FPFTY**	DIT - Distribution		($3,378)	100.00%	($3,378)	100.00%	($3,378)
10		DIT - CIAC			100.00%		100.00%	
11		Sub-total FPFTY	L9 + L10	($3,378)		($3,378)		($3,378)
12								
13		**Total**	L3 + L7 + L11	$277,875		$277,875		**$277,875**

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Line No.	Category	Description	Reference	(1) Pro Forma Adjusted at Present Rates	(2) Proposed Rate Increase	(3) Adjusted Amounts with Proposed Rate Increase
1	**Operating Revenues**	Residential		$1,616,602		$1,616,602
2		Residential - House Heating		358,922		358,922
3		C & I Small		417,041		417,041
4		C & I Large		237,936		237,936
5		Railroads & Railways		7,059		7,059
6		Street Lighting		22,848		22,848
7		Intercompany				
8		Transmission - All Classes		199,791		199,791
9		Forfeited Discounts		12,224	$1,403	13,627
10		Miscellaneous Service Revenues		3,684		3,684
11		Rent For Electric Property		22,580		22,580
12		Other Electric Revenues		9,534		9,534
13		Revenue Increase			$462,798	462,798
14		Total Operating Revenues	SUM L1 to L13	$2,908,221	$464,202	$3,372,423
15						
16	**Operating Expenses**	Power Supply		$1,003,713		$1,003,713
17		Transmission Expense		186,907		186,907
18		Distribution Expense		444,687		444,687
19		Customer Accounts Expense		162,107	$4,493	166,600
20		Customer Service and Information Expense		21,818		21,818
21		Sales Expense		422		422
22		Administrative & General		185,165	1,109	186,274
23		Sub-total O&M Expense	SUM L16 to L22	$2,004,819	$5,602	$2,010,421
24						
25		Depreciation & Amortization Expense		$336,287		$336,287
26		Amortization of Regulatory Expense		(448)		(448)
27		Taxes Other Than Income Taxes - Other		$192,334	$27,305	$219,640
28		Total Operating Expenses	SUM L23 to L27	$2,532,993	$32,907	$2,565,900
29						
30	**Net Operating Income - BIT**		L14 - L28	**$375,228**	**$431,294**	**$806,522**

Line No.	Category	Description	Reference	(1) FPFTY Amount Pre Adjustments	(2) Adjustments Sub-Total	(3) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential		$1,641,544	($24,942)	$1,616,602
2		Residential - House Heating		364,319	(5,396)	358,922
3		C & I Small		441,807	(24,766)	417,041
4		C & I Large		270,518	(32,581)	237,936
5		Railroads & Railways		8,121	(1,063)	7,059
6		Street Lighting		23,197	(349)	22,848
7		Intercompany				
8		Transmission - All Classes		199,791		199,791
9		Forfeited Discounts		12,224		12,224
10		Miscellaneous Service Revenues		3,684		3,684
11		Rent For Electric Property		22,580		22,580
12		Other Electric Revenues		9,534		9,534
13		Revenue Increase				
14		Total Operating Revenues	SUM L1 to L13	$2,997,318	($89,097)	$2,908,221
15						
16	**Operating Expenses**	Power Supply		$1,003,713		$1,003,713
17		Transmission Expense		186,907		186,907
18		Distribution Expense		427,846	$16,841	444,687
19		Customer Accounts Expense		147,808	14,298	162,107
20		Customer Service and Information Expense		103,916	(82,098)	21,818
21		Sales Expense		414	8	422
22		Administrative & General		178,632	6,533	185,165
23		Sub-total O&M Expense	SUM L16 to L22	$2,049,237	($44,418)	$2,004,819
24						
25		Depreciation & Amortization Expense		$318,997	$17,290	$336,287
26		Amortization of Regulatory Expense			(448)	(448)
27		Taxes Other Than Income Taxes - Other		197,517	(5,182)	192,334
28		Total Operating Expenses	SUM L23 to L27	$2,565,751	($32,758)	$2,532,993
29						
30	**Net Operating Income - BIT**		L14 - L28	**$431,567**	**($56,339)**	**$375,228**

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Line No.	Category	Description	Description	FPFTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Act 129 Lost Revenue	D-5D Energy Efficiency Program Cost Recovery	D-5E OPEN	D-5F Leap Year Adjustment	D-5G Weather Normalization
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Operating Revenues**	Residential	Elec Cost	$689,404							
2			Cust & Dist	952,140	$1,321	($1,568)	($1,930)	($23,263)		$498	
3			Sub-total Residential	$1,641,544	$1,321	($1,568)	($1,930)	($23,263)		$498	
4											
5		Residential - House Heating	Elec Cost	$180,937							
6			Cust & Dist	183,381	$991	($191)	($404)	($5,941)		$148	
7			Sub-total Residential - House Heating	$364,319	$991	($191)	($404)	($5,941)		$148	
8											
9		C & I Small	Elec Cost	$148,035							
10			Cust & Dist	293,772	$567		($892)	($24,597)		$155	
11			Sub-total C & I Small	$441,807	$567		($892)	($24,597)		$155	
12											
13		C & I Large	Elec Cost	$52,022							
14			Cust & Dist	218,495			($622)	($32,087)		$127	
15			Sub-total C & I Large	$270,518			($622)	($32,087)		$127	
16											
17		Railroads & Railways	Cust & Dist	$8,121				($1,063)			
18			Sub-total Railroads & Railways	$8,121				($1,063)			
19											
20		Street Lighting	Elec Cost	$801							
21			Cust & Dist	22,396				($349)			
22			Sub-total Street Lighting	$23,197				($349)			
23											
24		Intercompany	Elec Cost								
25			Cust & Dist								
26			Sub-total Interdepartmental								
27											
28		Transmission - All Classes	Transmission - All Classes	$199,791							
29			Sub-total Transmission - All Classes	$199,791							
30											
31		Forfeited Discounts	Forfeited Discounts	$12,224							
32			Sub-total Forfeited Discounts	$12,224							
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues	$3,684							
35			Sub-total Miscellaneous Service Revenues	$3,684							
36											
37		Rent For Electric Property	Rent For Electric Property	$22,580							
38			Sub-total Rent For Electric Property	$22,580							
39											
40		Other Electric Revenues	Other Electric Revenues	$9,534							
41			Sub-total Other Electric Revenues	$9,534							
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**	**$2,997,318**	**$2,879**	**($1,759)**	**($3,846)**	**($87,299)**		**$929**	
47											
48	**Operating Expenses**	Power Supply	Purchased Power	$1,003,713							

Line No.	Category	Description	Description	FPFTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Act 129 Lost Revenue	D-5D Energy Efficiency Program Cost Recovery	D-5E OPEN	D-5F Leap Year Adjustment	D-5G Weather Normalization
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
49			Sub-total Power Supply	$1,003,713							
50											
51		Transmission Expense	Operation & Supervision								
52			Load Dispatching								
53			Scheduling, System Control & Dispatch	93,988							
54			Transmission Service Studies								
55			Generation Service Studies								
56			Reliability, Planning & Standard Development	92,919							
57			Station Expense								
58			Overhead Lines								
59			Underground Lines Expense								
60			Miscellaneous Expense								
61			Rents								
62			Maintenance of Structures								
63			Maintenance of Computer Hardware								
64			Maintenance of Computer Software								
65			Maintenance of Communication Equipment								
66			Maintenance of Station Equipment								
67			Maintenance of Overhead Lines								
68			Maintenance of Underground Lines								
69			Maintenance of Misc Transmission Plant								
70			Sub-total Transmission Expense	186,907							
71											
72		Distribution Expense	Operation & Supervision	$1,271							
73			Load Dispatching								
74			Station Expense	816							
75			Overhead Lines Expenses	17,513							
76			Underground Lines Expense	14,687							
77			Meter Expenses	7,801							
78			Customer Installations Expense	14,386							
79			Miscellaneous Expense	90,014							
80			Rents	3,658							
81			Maintenance of Structures	6,622							
82			Maintenance of Station Equipment	18,529							
83			Maintenance of Overhead Lines	189,290							
84			Maintenance of Underground Lines	38,602							
85			Maintenance of Line Transformers	2,378							
86			Maintenance of Street Lighting & Signal Systems	1,990							
87			Maintenance of Misc. Distribution	20,293							
88			Sub-total Distribution Expense	$427,846							
89											
90		Customer Accounts	Supervision								
91			Meter Reading	$976							
92			Customer Records and Collection	105,441							
93			Uncollectible Accounts	38,095							
94			Miscellaneous Customer Accounts Expenses.	3,295							
95			Sub-total Total Customer Accounts	$147,808							
96											

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Category	Description	Description	FPFTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Act 129 Lost Revenue	D-5D Energy Efficiency Program Cost Recovery	D-5E OPEN	D-5F Leap Year Adjustment	D-5G Weather Normalization
97		Customer Service and Information	Customer Assistance	$101,517				($82,164)			
98			Informational & Instructional	1,407							
99			Miscellaneous Customer & Informational	992							
100			Sub-total Customer Service & Information	$103,916				($82,164)			
101											
102		Sales	Demonstrating & Selling	$414							
103			Miscellaneous Sales								
104			Sub-total Sales	$414							
105											
106		Administrative & General	Administrative and General Salaries	$29,889							
107			Office Supplies and Expenses	3,566							
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed	88,149							
110			Property Insurance	741							
111			Injuries & Damages	12,322							
112			Employee Pensions and Benefits	24,743							
113			Regulatory Commission Expenses	9,551							
114			Duplicate Charges-Credit	(1,092)							
115			Miscellaneous General Expenses	2,527							
116			Maintenance of General Plant	8,237							
117			Sub-total Administrative & General	$178,632							
118											
119			**Total O&M Expense**	$2,049,237				($82,164)			
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$318,997							
122			Sub-total Depreciation & Amortization Expense	$318,997							
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense								
125			Sub-total Amortization of Regulatory Expense								
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$197,517							
128			Sub-total Taxes Other Than Income Taxes - Other	$197,517							
129											
130			**Total Operating Expenses**	**$2,565,751**				**($82,164)**			
131											
132	**Net Operating Income Before Income Tax**			**$431,567**	**$2,879**	**($1,759)**	**($3,846)**	**($5,134)**		**$929**	

Line No.	Category	Description	Description	(9) D-6 Salary & Wages	(10) D-7 Rate Case Expense	(11) D-8 Adjustments for Employee Benefits	(12) D-9 Adjustments for Pension	(13) D-10 Uncollectible Accounts	(14) D-11 IIJA Reg Asset	(15) D-12 Customer Deposit Interest	(16) D-13 Storm
1	**Operating Revenues**	Residential	Elec Cost								
2			Cust & Dist								
3			Sub-total Residential								
4											
5		Residential - House Heating	Elec Cost								
6			Cust & Dist								
7			Sub-total Residential - House Heating								
8											
9		C & I Small	Elec Cost								
10			Cust & Dist								
11			Sub-total C & I Small								
12											
13		C & I Large	Elec Cost								
14			Cust & Dist								
15			Sub-total C & I Large								
16											
17		Railroads & Railways	Cust & Dist								
18			Sub-total Railroads & Railways								
19											
20		Street Lighting	Elec Cost								
21			Cust & Dist								
22			Sub-total Street Lighting								
23											
24		Intercompany	Elec Cost								
25			Cust & Dist								
26			Sub-total Interdepartmental								
27											
28		Transmission - All Classes	Transmission - All Classes								
29			Sub-total Transmission - All Classes								
30											
31		Forfeited Discounts	Forfeited Discounts								
32			Sub-total Forfeited Discounts								
33											
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues								
35			Sub-total Miscellaneous Service Revenues								
36											
37		Rent For Electric Property	Rent For Electric Property								
38			Sub-total Rent For Electric Property								
39											
40		Other Electric Revenues	Other Electric Revenues								
41			Sub-total Other Electric Revenues								
42											
43		Revenue Increase	Revenue Increase								
44			Sub-total Revenue Increase								
45											
46			**Total Operating Revenues**								
47											
48	**Operating Expenses**	Power Supply	Purchased Power								

Line No.	Category	Description	Description	(9) D-6 Salary & Wages	(10) D-7 Rate Case Expense	(11) D-8 Adjustments for Employee Benefits	(12) D-9 Adjustments for Pension	(13) D-10 Uncollectible Accounts	(14) D-11 IIJA Reg Asset	(15) D-12 Customer Deposit Interest	(16) D-13 Storm
49			Sub-total Power Supply								
50											
51		Transmission Expense	Operation & Supervision								
52			Load Dispatching								
53			Scheduling, System Control & Dispatch								
54			Transmission Service Studies								
55			Generation Service Studies								
56			Reliability, Planning & Standard Development								
57			Station Expense								
58			Overhead Lines								
59			Underground Lines Expense								
60			Miscellaneous Expense								
61			Rents								
62			Maintenance of Structures								
63			Maintenance of Computer Hardware								
64			Maintenance of Computer Software								
65			Maintenance of Communication Equipment								
66			Maintenance of Station Equipment								
67			Maintenance of Overhead Lines								
68			Maintenance of Underground Lines								
69			Maintenance of Misc Transmission Plant								
70			Sub-total Transmission Expense								
71											
72		Distribution Expense	Operation & Supervision	$35							
73			Load Dispatching								
74			Station Expense	2							
75			Overhead Lines Expenses	106							
76			Underground Lines Expense	87							
77			Meter Expenses	90							
78			Customer Installations Expense	219							
79			Miscellaneous Expense	247							
80			Rents								
81			Maintenance of Structures	46							
82			Maintenance of Station Equipment	303							
83			Maintenance of Overhead Lines	1,492							$13,468
84			Maintenance of Underground Lines	581							
85			Maintenance of Line Transformers	17							
86			Maintenance of Street Lighting & Signal Systems	4							
87			Maintenance of Misc. Distribution	144							
88			Sub-total Distribution Expense	$3,373							$13,468
89											
90		Customer Accounts	Supervision								
91			Meter Reading	$0							
92			Customer Records and Collection	1,265							
93			Uncollectible Accounts				$9,477				
94			Miscellaneous Customer Accounts Expenses.	27					$3,572		
95			Sub-total Total Customer Accounts	$1,292			$9,477		$3,572		
96											

				(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	Category	Description	Description	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 IIJA Reg Asset	D-12 Customer Deposit Interest	D-13 Storm
97		Customer Service and Information	Customer Assistance	$58							
98			Informational & Instructional								
99			Miscellaneous Customer & Informational	7							
100			Sub-total Customer Service & Information	$66							
101											
102		Sales	Demonstrating & Selling	$8							
103			Miscellaneous Sales								
104			Sub-total Sales	$8							
105											
106		Administrative & General	Administrative and General Salaries	$886							
107			Office Supplies and Expenses								
108			Administrative Expenses Transferred-Credit								
109			Outside Service Employed								
110			Property Insurance								
111			Injuries & Damages	62							
112			Employee Pensions and Benefits	1		$64	$3,272				
113			Regulatory Commission Expenses		$1,200						
114			Duplicate Charges-Credit								
115			Miscellaneous General Expenses	2							
116			Maintenance of General Plant	46							
117			Sub-total Administrative & General	$997	$1,200	$64	$3,272				
118											
119			**Total O&M Expense**	$5,736	$1,200	$64	$3,272	$9,477		$3,572	$13,468
120											
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense								
122			Sub-total Depreciation & Amortization Expense								
123											
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense						($448)		
125			Sub-total Amortization of Regulatory Expense						($448)		
126											
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other								
128			Sub-total Taxes Other Than Income Taxes - Other								
129											
130			**Total Operating Expenses**	**$5,736**	**$1,200**	**$64**	**$3,272**	**$9,477**	**($448)**	**$3,572**	**$13,468**
131											
132	**Net Operating Income Before Income Tax**			**($5,736)**	**($1,200)**	**($64)**	**($3,272)**	**($9,477)**	**$448**	**($3,572)**	**($13,468)**

Line No.	Category	Description	Description	(17) D-14 Other Adjustments	(18) D-15 OPEN	(19) D-16 Taxes Other Than Income	(20) D-17 Depreciation Annualization	(21) Adjustments Sub-total	(22) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Elec Cost						$689,404
2			Cust & Dist					($24,942)	927,198
3			Sub-total Residential					($24,942)	$1,616,602
4									
5		Residential - House Heating	Elec Cost						$180,937
6			Cust & Dist					($5,396)	177,985
7			Sub-total Residential - House Heating					($5,396)	$358,922
8									
9		C & I Small	Elec Cost						$148,035
10			Cust & Dist					($24,766)	269,006
11			Sub-total C & I Small					($24,766)	$417,041
12									
13		C & I Large	Elec Cost						$52,022
14			Cust & Dist					($32,581)	185,914
15			Sub-total C & I Large					($32,581)	$237,936
16									
17		Railroads & Railways	Cust & Dist					($1,063)	$7,059
18			Sub-total Railroads & Railways					($1,063)	$7,059
19									
20		Street Lighting	Elec Cost						$801
21			Cust & Dist					($349)	22,047
22			Sub-total Street Lighting					($349)	$22,848
23									
24		Intercompany	Elec Cost						
25			Cust & Dist						
26			Sub-total Interdepartmental						
27									
28		Transmission - All Classes	Transmission - All Classes						$199,791
29			Sub-total Transmission - All Classes						$199,791
30									
31		Forfeited Discounts	Forfeited Discounts						$12,224
32			Sub-total Forfeited Discounts						$12,224
33									
34		Miscellaneous Service Revenues	Miscellaneous Service Revenues						$3,684
35			Sub-total Miscellaneous Service Revenues						$3,684
36									
37		Rent For Electric Property	Rent For Electric Property						$22,580
38			Sub-total Rent For Electric Property						$22,580
39									
40		Other Electric Revenues	Other Electric Revenues						$9,534
41			Sub-total Other Electric Revenues						$9,534
42									
43		Revenue Increase	Revenue Increase						
44			Sub-total Revenue Increase						
45									
46			**Total Operating Revenues**					**($89,097)**	**$2,908,221**
47									
48	**Operating Expenses**	Power Supply	Purchased Power						$1,003,713

Line No.	Category	Description	Description	(17) D-14 Other Adjustments	(18) D-15 OPEN	(19) D-16 Taxes Other Than Income	(20) D-17 Depreciation Annualization	(21) Adjustments Sub-total	(22) Pro Forma Adjusted at Present Rates
49			Sub-total Power Supply						$1,003,713
50									
51		Transmission Expense	Operation & Supervision						
52			Load Dispatching						
53			Scheduling, System Control & Dispatch						93,988
54			Transmission Service Studies						
55			Generation Service Studies						
56			Reliability, Planning & Standard Development						92,919
57			Station Expense						
58			Overhead Lines						
59			Underground Lines Expense						
60			Miscellaneous Expense						
61			Rents						
62			Maintenance of Structures						
63			Maintenance of Computer Hardware						
64			Maintenance of Computer Software						
65			Maintenance of Communication Equipment						
66			Maintenance of Station Equipment						
67			Maintenance of Overhead Lines						
68			Maintenance of Underground Lines						
69			Maintenance of Misc Transmission Plant						
70			Sub-total Transmission Expense						186,907
71									
72		Distribution Expense	Operation & Supervision					$35	$1,306
73			Load Dispatching						
74			Station Expense					2	817
75			Overhead Lines Expenses					106	17,619
76			Underground Lines Expense					87	14,774
77			Meter Expenses					90	7,891
78			Customer Installations Expense					219	14,605
79			Miscellaneous Expense					247	90,261
80			Rents						3,658
81			Maintenance of Structures					46	6,667
82			Maintenance of Station Equipment					303	18,832
83			Maintenance of Overhead Lines					14,960	204,250
84			Maintenance of Underground Lines					581	39,183
85			Maintenance of Line Transformers					17	2,395
86			Maintenance of Street Lighting & Signal Systems					4	1,993
87			Maintenance of Misc. Distribution					144	20,437
88			Sub-total Distribution Expense					$16,841	$444,687
89									
90		Customer Accounts	Supervision						
91			Meter Reading					$0	$976
92			Customer Records and Collection					1,265	106,706
93			Uncollectible Accounts					9,477	47,573
94			Miscellaneous Customer Accounts Expenses.	($43)				3,556	6,852
95			Sub-total Total Customer Accounts	($43)				$14,298	$162,107
96									

Line No.	Category	Description	Description	(17) D-14 Other Adjustments	(18) D-15 OPEN	(19) D-16 Taxes Other Than Income	(20) D-17 Depreciation Annualization	(21) Adjustments Sub-total	(22) Pro Forma Adjusted at Present Rates
97		Customer Service and Information	Customer Assistance					($82,106)	$19,411
98			Informational & Instructional						1,407
99			Miscellaneous Customer & Informational					7	1,000
100			Sub-total Customer Service & Information					($82,098)	$21,818
101									
102		Sales	Demonstrating & Selling					$8	$422
103			Miscellaneous Sales						
104			Sub-total Sales					$8	$422
105									
106		Administrative & General	Administrative and General Salaries					$886	$30,775
107			Office Supplies and Expenses						3,566
108			Administrative Expenses Transferred-Credit						
109			Outside Service Employed						88,149
110			Property Insurance						741
111			Injuries & Damages					62	12,384
112			Employee Pensions and Benefits					3,337	28,080
113			Regulatory Commission Expenses					1,200	10,751
114			Duplicate Charges-Credit						(1,092)
115			Miscellaneous General Expenses	$1,000				1,002	3,529
116			Maintenance of General Plant					46	8,283
117			Sub-total Administrative & General	$1,000				$6,533	$185,165
118									
119			**Total O&M Expense**	$957				($44,418)	$2,004,819
120									
121		Depreciation & Amortization Expense	Depreciation & Amortization Expense				$17,290	$17,290	$336,287
122			Sub-total Depreciation & Amortization Expense				$17,290	$17,290	$336,287
123									
124		Amortization of Regulatory Expense	Amortization of Regulatory Expense					($448)	($448)
125			Sub-total Amortization of Regulatory Expense					($448)	($448)
126									
127		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other			($5,182)		($5,182)	$192,334
128			Sub-total Taxes Other Than Income Taxes - Other			($5,182)		($5,182)	$192,334
129									
130			**Total Operating Expenses**	**$957**		**($5,182)**	**$17,290**	**($32,758)**	**$2,532,993**
131									
132	**Net Operating Income Before Income Tax**			**($957)**		**$5,182**	**($17,290)**	**($56,339)**	**$375,228**

Line No.	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5D Energy Efficiency Program Expense	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 IIJA Reg Asset
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.	$1,003,713							
2			Sub-total Power Supply	$1,003,713							
3											
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision								
5			561.0 Load Dispatching								
6			561.4 Scheduling, System Control & Dispatch	93,988							
7			561.6 Transmission Service Studies								
8			561.7 Generation Service Studies								
9			561.8 Reliability, Planning & Standard Development	92,919							
10			562.0 Station Expense								
11			563.0 Overhead Lines								
12			564.0 Underground Lines Expense								
13			566.0 Miscellaneous Expense								
14			567.0 Rents								
15			Sub-total Transmission Operations	186,907							
16											
17		**Transmission Maintenance**	569.0 Maintenance of Structures								
18			569.1 Maintenance of Computer Hardware								
19			569.2 Maintenance of Computer Software								
20			569.3 Maintenance of Communication Equipment								
21			570.0 Maintenance of Station Equipment								
22			571.0 Maintenance of Overhead Lines								
23			572.0 Maintenance of Underground Lines								
24			573.0 Maintenance of Misc Transmission Plant								
25			Sub-total Transmission Maintenance								
26											
27			Sub-total TRANSMISSION EXPENSE	186,907							
28											
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision	$1,271	$35						
30			581.0 Load Dispatching								
31			582.0 Station Expense	816	2						
32			583.0 Overhead Lines Expenses	17,513	106						
33			584.0 Underground Lines Expense	14,687	87						
34			586.0 Meter Expenses	7,801	90						
35			587.0 Customer Installations Expense	14,386	219						
36			588.0 Miscellaneous Expense	90,014	247						
37			589.0 Rents	3,658							
38			Sub-total Distribution Operations	$150,143	$787						
39											
40		**Distribution Maintenance**	591.0 Maintenance of Structures	$6,622	$46						
41			592.0 Maintenance of Station Equipment	18,529	303						
42			593.0 Maintenance of Overhead Lines	189,290	1,492						
43			594.0 Maintenance of Underground Lines	38,602	581						
44			595.0 Maintenance of Line Transformers	2,378	17						
45			596.0 Maintenance of Street Lighting & Signal Systems	1,990	4						
46			598.0 Maintenance of Misc. Distribution	20,293	144						
47			Sub-total Distribution Maintenance	$277,703	$2,587						
48											

					(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Category	Description	Account		FPFTY Amount Pre Adjustments	D-5D Energy Efficiency Program Expense	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 IIJA Reg Asset
49			Sub-total DISTRIBUTION EXPENSE		$427,846		$3,373					
50												
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision									
52			902.0 Meter Reading		$976		0					
53			903.0 Customer Records and Collection		105,441		1,265					
54			904.0 Uncollectible Accounts.		38,095						9,477	
55			905.0 Miscellaneous Customer Accounts Expenses.		3,295		27					
56			Sub-total Customer Accounts		$147,808		$1,292				$9,477	
57												
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance		$101,517	($82,164)	$58					
59			909.0 Informational & Instructional		1,407							
60			910.0 Miscellaneous Customer & Informational		992		7					
61			Sub-total Customer Service & Information		$103,916	($82,164)	$66					
62												
63	**SALES**	**Sales**	912.0 Demonstrating & Selling		$414		$8					
64			916.0 Miscellaneous Sales									
65			Sub-total Sales		$414		$8					
66												
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries		$29,889		$886					
68			921.0 Office Supplies and Expenses		3,566							
69			922.0 Administrative Expenses Transferred-Credit									
70			923.0 Outside Service Employed		88,149							
71			924.0 Property Insurance		741							
72			925.0 Injuries & Damages		12,322		62					
73			926.0 Employee Pensions and Benefits		24,743		1			64	3,272	
74			928.0 Regulatory Commission Expenses		9,551			1,200				
75			929.0 Duplicate Charges-Credit		(1,092)							
76			930.2 Miscellaneous General Expenses		2,527		2					
77			Sub-total A&G Operations		$170,395		$951	$1,200		$64	$3,272	
78												
79		A&G Maintenance	935.0 Maintenance of General Plant		$8,237		$46					
80												
81			Sub-total ADMINISTRATION & GENERAL		$178,632		$997	$1,200		$64	$3,272	
82												
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.		$268,901							
84			404.0 Amort. Of Limited-Term Electric Plant.		50,096							
85			Sub-total Depreciation & Amortization Expense		$318,997							
86												
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.									($448)
88			Sub-total Amortization of Regulatory Expense									($448)
89												
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.		$197,517							
91			Sub-total Taxes Other Than Income Taxes - Other		$197,517							
92												
93			**Total**		**$2,565,751**	**($82,164)**	**$5,736**	**$1,200**	**$64**	**$3,272**	**$9,477**	**($448)**

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 Storm	(11) D-14 Other Adjustments	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
1	**POWER SUPPLY EXPENSES**	**Power Supply**	555.0 Purchased Power.								$1,003,713
2			Sub-total Power Supply								$1,003,713
3											
4	**TRANSMISSION EXPENSE**	**Transmission Operations**	560.0 Operation & Supervision								
5			561.0 Load Dispatching								
6			561.4 Scheduling, System Control & Dispatch								93,988
7			561.6 Transmission Service Studies								
8			561.7 Generation Service Studies								
9			561.8 Reliability, Planning & Standard Development								92,919
10			562.0 Station Expense								
11			563.0 Overhead Lines								
12			564.0 Underground Lines Expense								
13			566.0 Miscellaneous Expense								
14			567.0 Rents								
15			Sub-total Transmission Operations								186,907
16											
17		**Transmission Maintenance**	569.0 Maintenance of Structures								
18			569.1 Maintenance of Computer Hardware								
19			569.2 Maintenance of Computer Software								
20			569.3 Maintenance of Communication Equipment								
21			570.0 Maintenance of Station Equipment								
22			571.0 Maintenance of Overhead Lines								
23			572.0 Maintenance of Underground Lines								
24			573.0 Maintenance of Misc Transmission Plant								
25			Sub-total Transmission Maintenance								
26											
27			Sub-total TRANSMISSION EXPENSE								186,907
28											
29	**DISTRIBUTION EXPENSE**	**Distribution Operations**	580.0 Operation & Supervision							$35	$1,306
30			581.0 Load Dispatching								
31			582.0 Station Expense							$2	$817
32			583.0 Overhead Lines Expenses							$106	$17,619
33			584.0 Underground Lines Expense							$87	$14,774
34			586.0 Meter Expenses							$90	$7,891
35			587.0 Customer Installations Expense							$219	$14,605
36			588.0 Miscellaneous Expense							$247	$90,261
37			589.0 Rents								$3,658
38			Sub-total Distribution Operations							$787	$150,930
39											
40		**Distribution Maintenance**	591.0 Maintenance of Structures							$46	$6,667
41			592.0 Maintenance of Station Equipment							303	18,832
42			593.0 Maintenance of Overhead Lines		13,468					14,960	204,250
43			594.0 Maintenance of Underground Lines							581	39,183
44			595.0 Maintenance of Line Transformers							17	2,395
45			596.0 Maintenance of Street Lighting & Signal Systems							4	1,993
46			598.0 Maintenance of Misc. Distribution							144	20,437
47			Sub-total Distribution Maintenance		$13,468					$16,055	$293,757
48											

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 Storm	(11) D-14 Other Adjustments	(12) D-15 OPEN	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
49			Sub-total DISTRIBUTION EXPENSE		$13,468					$16,841	$444,687
50											
51	**CUSTOMER ACCOUNTS**	**Customer Accounts**	901.0 Supervision								
52			902.0 Meter Reading							$0	$976
53			903.0 Customer Records and Collection							$1,265	106,706
54			904.0 Uncollectible Accounts.							9,477	47,573
55			905.0 Miscellaneous Customer Accounts Expenses.	3,572		($43)				3,556	6,852
56			Sub-total Customer Accounts	$3,572		($43)				$14,298	$162,107
57											
58	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance							($82,106)	$19,411
59			909.0 Informational & Instructional								1,407
60			910.0 Miscellaneous Customer & Informational							7	1,000
61			Sub-total Customer Service & Information							($82,098)	$21,818
62											
63	**SALES**	**Sales**	912.0 Demonstrating & Selling							$8	$422
64			916.0 Miscellaneous Sales								
65			Sub-total Sales							$8	$422
66											
67	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative and General Salaries							$886	$30,775
68			921.0 Office Supplies and Expenses								3,566
69			922.0 Administrative Expenses Transferred-Credit								
70			923.0 Outside Service Employed								88,149
71			924.0 Property Insurance								741
72			925.0 Injuries & Damages							62	12,384
73			926.0 Employee Pensions and Benefits							3,337	28,080
74			928.0 Regulatory Commission Expenses							1,200	10,751
75			929.0 Duplicate Charges-Credit								(1,092)
76			930.2 Miscellaneous General Expenses			1,000				1,002	3,529
77			Sub-total A&G Operations			$1,000				$6,487	$176,882
78											
79		A&G Maintenance	935.0 Maintenance of General Plant							$46	$8,283
80											
81			Sub-total ADMINISTRATION & GENERAL			$1,000				$6,533	$185,165
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$15,117	$15,117	$284,018
84			404.0 Amort. Of Limited-Term Electric Plant.						2,172	2,172	52,269
85			Sub-total Depreciation & Amortization Expense						$17,290	$17,290	$336,287
86											
87	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.							($448)	($448)
88			Sub-total Amortization of Regulatory Expense							($448)	($448)
89											
90	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					($5,182)		($5,182)	$192,334
91			Sub-total Taxes Other Than Income Taxes - Other					($5,182)		($5,182)	$192,334
92											
93			**Total**	**$3,572**	**$13,468**	**$957**		**($5,182)**	**$17,290**	**($32,758)**	**$2,532,993**

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Line No.	Category	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Act - 129 Lost Revenue Due To Load Reduction	(5) D-5D Energy Efficiency Program Cost Recovery	(6) D-5E OPEN	(7) D-5F Leap Year Adjustment	(8) D-5G Weather Normalization	(9) Adjustments Sub-total	(10) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	440.0	$952,140	$1,321	($1,568)	($1,930)	($23,263)		$498		($24,942)	$927,198
2			Residential - House Heating	440.1	183,381	991	(191)	(404)	(5,941)		148		(5,396)	177,985
3			C & I Small	442.0	293,772	567		(892)	(24,597)		155		(24,766)	269,006
4			C & I Large	442.1	218,495			(622)	(32,087)		127		(32,581)	185,914
5			Railroads & Railways	446.0	8,121				(1,063)				(1,063)	7,059
6			Street Lighting	444.0	22,396				(349)				(349)	22,047
7			Intercompany	448.0										
8			Transmission - All Classes		199,791									199,791
9			Sub-total - Customer & Distribution Revenues		$1,878,096	$2,879	($1,759)	($3,846)	($87,299)		$929		($89,097)	$1,788,999
10														
11		**Electric Cost Revenue**	Residential	440.0	$689,404									$689,404
12			Residential - House Heating	440.1	180,937									180,937
13			C & I Small	442.0	148,035									148,035
14			C & I Large	442.1	52,022									52,022
15			Railroads & Railways	446.0										
16			Street Lighting	444.0	801									801
17			Intercompany	448.0										
18			Sub-total - Electric Cost Revenue		$1,071,200									$1,071,200
19														
20			**Total OPERATING REVENUE**		$2,949,296	$2,879	($1,759)	($3,846)	($87,299)		$929		($89,097)	$2,860,199
21														
22	*OTHER REVENUE*	**Other Electric Revenue**	Rent For Electric Property	454.0	$22,580									$22,580
23			Other Electric Revenues	456.0	9,534									9,534
24			Transmission of Electricity for Others	456.1										
25			Sub-total - Other electric Revenue		$32,114									$32,114
26														
27		**Other Operating Revenue**	Forfeited Discounts	450.0	$12,224									$12,224
28			Miscellaneous Service Revenues	451.0	3,684									3,684
29			Sub-total - Other Operating Revenue		$15,908									$15,908
30														
31			**Total OTHER REVENUE**		$48,022									$48,022
32														
33			**Total REVENUE**		**$2,997,318**	**$2,879**	**($1,759)**	**($3,846)**	**($87,299)**		**$929**		**($89,097)**	**$2,908,221**

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		(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Reference	440000: Residental Sales	440001: Residental Heating Sales	442001: C&I Sales-Small	442002: C&I Sales-Large	C & I Total
1	Total FPFTY Revenues		$1,754,162	$393,755	$475,391	$293,645	$769,035
2	Commodity Billings in Revenues		(802,022)	(210,374)	(181,619)	(75,149)	(256,768)
3	Weather Adjustment						
4	Total Reconcilable Surcharge in Revenues		(16,861)	(4,269)	(20,111)	(23,703)	(43,814)
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$935,279	$179,112	$273,661	$194,792	$468,453
6							
7	Average Monthly Customers in FPFTY		1,338,774	204,336	156,564	3,110	159,674
8							
9	Average Annual Margin Per Customer	L5 / L7	$0.699	$0.877	$1.748	$62.634	$2.934
10							
11	Number of Customers at end of FPFTY		1,340,665	205,467	156,888	3,110	159,998
12							
13	Increase in Customers during FPFTY	L11 - L7	1,891	1,131	324		324
14							
15	**Annualization of Revenue**	L9 * L13	**$1,321**	**$991**	**$567**		**$567**

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Line No.	Description	Reference	(1) 440000: Residental Sales	(2) 440001: Residental Heating Sales
1	CAP Discount		($129,368)	($15,786)
2				
3				
4	**ANNUALIZATION TO YEAR END CUSTOMERS**			
5				
6	Annual CAP Customers		1,395,081	175,423
7	Average Monthly CAP Customers		116,257	14,619
8	Average Annual CAP Discount Per Customer	L1 / L7	($1.113)	($1.080)
9				
10	CAP Customers at End of FPFTY		117,860	14,820
11	Increase of CAP Customers	L10 - L7	1,603	201
12				
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	($1,784)	($218)
14	Write-Offs & Working Capital Factor		12.1%	12.1%
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	$216	$26
16				
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**($1,568)**	**($191)**

Line No.	Description	Reference	(1) 2025 Revenue Loss	(2) 2026 Revenue Loss	(3) 2026 Revenue Loss Over 2025	(4) Recovery of Incremental Revenue Loss
1	**Revenue Impact in 2025 - Included in FPFTY Year Budget**					
2	Residential		($3,767)			
3	Residential Heaing		(788)			
4	Small C&I		(2,276)			
5	Large C&I		(1,583)			
6	Total	SUM L2 to L5	($8,413)			
7						
8	**Target Revenue Impact in 2026**					
9	Residential			($7,626)		
10	Residential Heaing			(1,595)		
11	Small C&I			(4,060)		
12	Large C&I			(2,826)		
13	Total	SUM L9 to L12		($16,106)		
14						
15	**Incremental Revenue Impact Over FPFTY Budget**					
16	Residential	L9 - L2			($3,859)	
17	Residential Heaing	L10 - L3			(807)	
18	Small C&I	L11 - L4			(1,783)	
19	Large C&I	L12 - L5			(1,244)	
20	Total	SUM L16 to L19			($7,693)	
21						
22	**Average Annual Incremental Revenue Not in FPFTY Budget**					
23	Residential	L16 / 2				($1,930)
24	Residential Heaing	L17 / 2				(404)
25	Small C&I	L18 / 2				(892)
26	Large C&I	L19 / 2				(622)
27	**Total**	SUM L23 to L26				($3,846)

		(1)	(2)
Line No.	Account / Description	Reference	Total
1	440000: Residential Sales		($23,263)
2	440001: Residential Heating Sales		(5,941)
3	442001: C&I Sales-Small		(24,597)
4	442002: C&I Sales-Large		(32,087)
5	444000: Public Street/Highway Lighting		(349)
6	446000: Sales-Railroad/Railway		(1,063)
7	**Reduction in Retail Revenue**	SUM L1 to L6	**($87,299)**
8			
9	O&M Expense		($82,164)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Reference	440000: Residental Sales	440001: Residental Heating Sales	442001: C&I Sales-Small	442002: C&I Sales-Large	C & I Total
1	Revenue in February of FPFTY		$55,822	$16,572	$17,409	$14,220	$31,629
2	Days in February of FPFTY		28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	$1,994	$592	$622	$508	
4	Average Days in February		28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	
6							
7	**Leap Year Adjustment**	L3 * L5	**$498**	**$148**	**$155**	**$127**	**$282**

(1)

Line No.	Account	Total
1	Residental Sales	
2	Residental Heating Sales	
3	C&I Sales-Small	
4	C&I Sales-Large	
5		
6	**Total**	

Line No.	Description	Reference	(1) Union	(2) Non-Union
1	Number of Employees @ HTY - Union/Non-Union		1,044	1,168
2	Number of Employees @ HTY - Total		2,213	2,213
3	Percentage of Employees @ HTY	L1 / L2	47.20%	52.80%
4	Distribution of Budget S&W Expense		$79,266	$88,656
5				
6	**Annualize March 1 Wage Increase for FPFTY**			
7	Number of Months TY			2
8	Rate for Increase TY		2.50%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$443
10		L4 + L9	$79,266	$89,099
11				
12	**Annualize January 1 and March 1, 2026 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		2.50%	3.00%
15	Total Adjustment	(L10 * L13 * L14) / 12	$1,982	$2,673
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$81,248**	**$91,772**

Line No.	Description	(1) Reference	(2) Amount
1	Distribution of S&W Expense		$167,922
2			
3	Annualized S&W Including Wage Increases		$173,020
4			
5	**Adjustment for Union Contract**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		77.49%
8	Union Contract Payment for Utility	L6 * L7	$1,010
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$168
11			
12	Adjusted S&W for Employees in FPFTY	L3 + L10	$173,189
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ FPFTY		2,373
16	Average Number of Employees in FPFTY - Total		2,366
17	Annualization for Number of Employees	L15 - L16	6
18	Annual S&W per Employee	L12 / L16	$73
19	Annualization of S&W for New Employees	L17 * L18	$470
20			
21	Pro Forma FPFTY S&W	L12 + L19	$173,658
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$5,736**
24			
25	S&W Pro Forma Factor	L23 / L1	3.42%

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
1	**Operations**	**Power Supply Expenses**	555.0 Purchased Power.			
2			Sub-total Power Supply Expenses			
3						
4		**Transmission Expense**	560.0 Operation & Supervision			
5			561.0 Load Dispatching			
6			561.4 Scheduling, System Control & Dispatch			
7			561.6 Transmission Service Studies			
8			561.7 Generation Service Studies			
9			561.8 Reliability, Planning & Standard Development			
10			562.0 Station Expense			
11			563.0 Overhead Lines			
12			564.0 Underground Lines Expense			
13			566.0 Miscellaneous Expense			
14			567.0 Rents			
15			569.0 Maintenance of Structures			
16			569.1 Maintenance of Computer Hardware			
17			569.2 Maintenance of Computer Software			
18			569.3 Maintenance of Communication Equipment			
19			570.0 Maintenance of Station Equipment			
20			571.0 Maintenance of Overhead Lines			
21			572.0 Maintenance of Underground Lines			
22			573.0 Maintenance of Misc Transmission Plant			
23			Sub-total Transmission Expense			
24						
25		**Distribution Expense**	580.0 Operation & Supervision	$1,029	$35	$1,065
26			581.0 Load Dispatching			
27			582.0 Station Expense	53	2	55
28			583.0 Overhead Lines Expenses	3,114	106	3,221
29			584.0 Underground Lines Expense	2,554	87	2,641
30			586.0 Meter Expenses	2,646	90	2,737
31			587.0 Customer Installations Expense	6,411	219	6,630
32			588.0 Miscellaneous Expense	7,221	247	7,468
33			589.0 Rents			
34			591.0 Maintenance of Structures	1,341	46	1,387
35			592.0 Maintenance of Station Equipment	8,863	303	9,165
36			593.0 Maintenance of Overhead Lines	43,678	1,492	45,170
37			594.0 Maintenance of Underground Lines	17,015	581	17,596
38			595.0 Maintenance of Line Transformers	496	17	513
39			596.0 Maintenance of Street Lighting & Signal Systems	103	4	107
40			598.0 Maintenance of Misc. Distribution	4,228	144	4,372
41			Sub-total Distribution Operations	$98,752	$3,373	$102,126
42						

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
43	**Customer Accounts**		901.0 Supervision			
44			902.0 Meter Reading	$0	$0	$0
45			903.0 Customer Records and Collection	37,027	1,265	38,292
46			904.0 Uncollectible Accounts.			
47			905.0 Miscellaneous Customer Accounts Expenses.	790	27	817
48			Sub-total Customer Accounts	$37,817	$1,292	$39,109
49						
50	**Customer Service & Information**		908.0 Customer Assistance	$1,710	$58	$1,768
51			909.0 Informational & Instructional			
52			910.0 Miscellaneous Customer & Informational	219	7	226
53			Sub-total Customer Service & Information	$1,928	$66	$1,994
54						
55	**Sales**		912.0 Demonstrating & Selling	$228	$8	$236
56			916.0 Miscellaneous Sales			
57			Sub-total Sales	$228	$8	$236
58						
59	**Administration & General**		920.0 Administrative and General Salaries	$25,929	$886	$26,815
60			921.0 Office Supplies and Expenses			
61			922.0 Administrative Expenses Transferred-Credit			
62			923.0 Outside Service Employed			
63			924.0 Property Insurance			
64			925.0 Injuries & Damages	1,824	62	1,887
65			926.0 Employee Pensions and Benefits	35	1	36
66			928.0 Regulatory Commission Expenses			
67			929.0 Duplicate Charges-Credit			
68			930.2 Miscellaneous General Expenses	62	2	64
69			935.0 Maintenance of General Plant	1,345	46	1,391
70			Sub-total Administration & General	$29,195	$997	$30,193
71						
72			**Total**	**$167,922**	**$5,736**	**$173,658**
73						
74	**Percent Increas**		**Percent Increase**			3.42%

		(1)	(2)
Line No.	Description	Reference	Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$3
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		6
4	Total Recorded Up To Period End of HTY	SUM L2 to L3	$9
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$1,997
8	Materials, IT Costs, Travel, Copies, etc.		394
9	Total Expenditure Expected in FTY	SUM L7 to L8	$2,391
10			
11	Total Rate Case Expense	L4 + L9	$2,400
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,200
15			
16	Annual Amortization Amount Included in Budget		
17	**Pro Forma Adjustment for Annual Amortization**	L14 - L16	**$1,200**

Line No.	Description	Reference	(1) Jurisdictional Amount
1	**Number of Employees**		
2	Employees at Eleven Months Prior		2,359
3	Employees at Ten Months Prior		2,363
4	Employees at Nine Months Prior		2,358
5	Employees at Eight Months Prior		2,358
6	Employees at Seven Months Prior		2,360
7	Employees at Six Months Prior		2,363
8	Employees at Five Months Prior		2,364
9	Employees at Four Months Prior		2,366
10	Employees at Three Months Prior		2,377
11	Employees at Two Months Prior		2,377
12	Employees at One Month Prior		2,379
13	Employees at End of FPFTY		2,373
14			
15	Average Monthly Employees in FPFTY	AVERAGE L2 to L13	2,366
16	Additional Employees in FPFTY		6
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$23,617
20	Number of Employees for Budget		2,366
21	Budget Expense Per Employee	L19 / L20	$10
22	Additional Employees for Annualization	L16	6
23	**Total Benefits Pro Forma Adjustment**	L21 * L22	**$64**

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	Pension Contribution for Four Years Prior to FPFTY		$17,267
2	Pension Contribution for Three Years Prior to FPFTY		15,222
3	Pension Contribution for Two Years Prior to FPFTY		1,408
4	Pension Contribution for One Year Prior to FPFTY		2,878
5	Pension Contribution for FPFTY		3,300
6			
7	Average Pension Contribution	Average L1 to L5	$8,015
8			
9	Percent to Electric Distribution		77.49%
10	Total Amount to Electric Distribution	L7 * L9	$6,211
11	Pension Capitalization Factor		48.21%
12	Pension Contribution To Be Capitalized	L10 * L11	2,994
13	Pension Contribution To Be Expensed	L10 - L12	$3,216
14	FPFTY Distribution Pension Expense		(56)
15	**Additional Pension Expense**	L13 - L14	**$3,272**

Line No.	Description	(1) Reference	(2) Reference	(3) Charge Off Amounts	(4) InPA Charge Off Amounts	(5) Net Charge Off Amounts	(6) Billed Revenue	(7) Percent	(8) PPA	(9) Totals
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$29,237	$2,395	$26,842	$3,365,014	0.7977%		
2		One Year Prior to HTY		37,820	(28)	37,848	3,810,090	0.9934%		
3		HTY		42,650	17	42,632	3,880,008	1.0988%		
4		Three Year Average	SUM L1 to L3 / 3	$36,569	$795	$35,774	$3,685,037	0.9708%		
5										
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	FPFTY					$2,860,199			
7										
8	Tariff Revenue - Non Shopping Revenue	FPFTY	L6				$2,860,199			
9										
10	Tariff Revenue - Shopping Revenue	FPFTY					1,082,504			
11										
12	Tariff Revenue - Including Shopping Revenue	FPFTY	L8 + L10				$3,942,703			
13										
14	**Total General Pro Forma Uncollectible Accounts**		Col 7 L4 * L12							$38,275
15										
16	**NET PPA UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY						$6,462		
17		One Year Prior to HTY						9,314		
18		HTY						12,116		
19										
20	**Three Year Average PPA**		SUM L16 to L18 / 3							$9,297
21										
22	**Total Pro Forma Uncollectible Accounts**		L14 + L20							$47,573
23										
24	Uncollectible Accounts (904)	FPFTY								$38,095
25										
26	**Total Pro Forma Adjustment for Uncollectible Accounts**		L22 - L24							**$9,477**

Line No.	Description	(1) Reference	(2) Total
1	Actual IIJA Related Incremental Costs in 2022 and 2023		$411
2	Amortization Years		2
3	Pro Forma Adjustment Amount	L1 / L2	$205
4	Remove Estimated IIJA Related Incremental Costs in 2025		(653)
5	Total Pro Forma Adjustment Amount	L3 + L4	($448)

Line No.	Description	Description	Reference	Interest Rate	Deposit Amount	Interest on Deposit Amount	Interest Sub Total	Interest Total
			(1)	(2)	(3)	(4)	(5)	(6)
1	**Residential**	Monthly Interest Rate		0.667%				
2								
3	January				18,976	127		
4	February				19,166	128		
5	March				19,446	130		
6	April				20,077	134		
7	May				20,877	139		
8	June				21,538	144		
9	July				22,060	147		
10	August				22,549	150		
11	September				22,772	152		
12	October				23,058	154		
13	November				23,276	155		
14	December				23,215	155		
15	**Total Residential**		SUM Col 4 L3 to L14				$1,713	
16								
17	**Non-Residential**	Monthly Interest Rate		0.425%				
18								
19	January				32,487	138		
20	February				33,197	141		
21	March				33,844	144		
22	April				34,307	146		
23	May				35,117	149		
24	June				35,642	151		
25	July				36,988	157		
26	August				38,022	162		
27	September				38,782	165		
28	October				39,358	167		
29	November				39,646	168		
30	December				39,988	170		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$1,859	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					**$3,572**

Line No.	Description	Reference	Tri- State CPI Factor	Inflation Factor	Expense In Year	Amount for Average	Total
		(1)	(2)	(3)	(4)	(5)	(6)
1	4/1/2019 - 3/31/2020		-	1.22049	$32,500	$39,666	
2	4/1/2020 - 3/31/2021		0.00696	1.22049	$118,822	$145,021	
3	4/1/2021 - 3/31/2022		0.05645	1.21206	$56,495	$68,475	
4	4/1/2022 - 3/31/2023		0.07555	1.14730	$17,144	$19,670	
5	4/1/2023 - 3/31/2024		0.03888	1.06670	$63,792	$68,047	
6	2024		0.01671	1.02679			
7	2025		0.00991	1.00991			
8							
9	Average Storm Restoration Expense at 2025 cost levels	AVERAGE L1 to L5					$68,176
10							
11	FPFTY Budget						$54,708
12							
13	**Pro Forma Adjustment for Storm Expense Normalization**	L9 - L11					**$13,468**

Line No.	Description	(1) Reference	(2) Total
1	Final Tax Accounting Repair Credit (TARC) - Electric		
2	Residential		($36)
3	Small C&I		(14)
4	Large C&I		(9)
5	Street Lighting		(3)
6	Sub-total TARC Credit	SUM L2 to L5	($62)
7	Final Federal Tax Adjustment Credit (FTAC) - Electric		
8	Residential		($37)
9	Small C&I		(1)
10	Street Lighting		(0)
11	Large C&I & Railroads		15
12	Sub-total FTAC Credit	SUM L8 to L11	($23)
13	Total TARC and FTAC Credit	L6 + L12	($86)
14	Amortization Years		2
15	Pro Forma Adjustment Amount	L13 / L14	($43)
16			
17	EV Incentive Rebates		$1,000

Line No.	Description	Transmission Percentage / Reference	Total Electric	Transmission Elimination	Distribution	Pro Forma Adjustments	Pro Forma Tax Expense
		(1)	(2)	(3)	(4)	(5)	(6)
1	Public Utility Real Tax (PURTA) Total Expense	17.825%	$6,924	($1,234)	$5,690		$5,690
2	Use Tax Accrued	17.825%	2,443	(435)	2,007		2,007
3	Real Estate Tax Accrued	17.825%	5,988	(1,067)	4,920		4,920
4	Miscellaneous TOTI	12.373%					
5	Payroll Tax Accrued	12.373%	14,402	(1,782)	12,620	431	13,051
6	Sub-total TOTI - Other	SUM L1 to L5	$29,756	($4,519)	$25,237	$431	$25,668
7							
8	Gross Receipt Tax		$172,280		$172,280	($5,614)	$166,666
9							
10	**Total**	L6 + L8	**$202,036**	**($4,519)**	**$197,517**	**($5,182)**	**$192,334**

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Total Payroll Charged to Expense		$167,922
2	Payroll Tax Expense		$12,620
3	Payroll Tax Expense - Percent	L2 / L1	7.52%
4	Pro Forma Increase in S&W		$5,736
5	**Payroll Tax Pro Forma**	L3 * L4	**$431**

D-1□ TOTI - Gro□□ Re□ei□t□ Pro For□ a

Line No.	Description	Reference	(1) Total
1	**GROSS RECEIPTS TAX PRO FORMA AT PRESENT RATE**		(2)
2			
3	Residential		$1,616,602
4	Residential Heating		358,922
5	Small C&I		417,041
6	Large C&I		237,936
7	Railroads & Railways		7,059
8	Street Lighting & Highway		22,848
9	Interdepartmental Sales - Electric		
10	Transmission		199,791
11	Sub-total	SUM L3 to L10	$2,860,199
12			
13	Forfeited Discounts - Electric		$12,224
14	Uncollectible Accounts		(47,573)
15	COVID-19 Related Incremental Bad Debt Expense		
16	Sub-total	SUM L13 to L15	($35,349)
17			
18	Total FPFTY at Present Rates	L11 + L16	$2,824,851
19			
20	Gross Receipts Tax Rate		5.90%
21			
22	Pro Forma Gross Receipts Expense at Present Rates	L18 * L20	$166,666
23			
24	FPFTY Budget		$172,280
25			
26	**Net Adjustment**	L22 - L24	**($5,614)**

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	$2,703	$357	$2,346	$357	$3,060
2			PECO Elec 3650 PA LTIIP	4,037	440	3,597	440	4,478
3			PECO Elec 3660 PA LTIIP	4,615	723	3,892	723	5,338
4			PECO Elec 3670 PA LTIIP	6,084	764	5,320	764	6,847
5			PECO Elec 3705 SM UD RES PA	9,577		9,577		9,577
6			PECO Elec 3706 Non DOE Rcv PA	2,210		2,210		2,210
7			PECO Elec 3707 SM RES PA	5,764	96	5,668	96	5,861
8			PECO Elec 3708 SM SCI PA	832	3	829	3	835
9			PECO Elec 3709 SM LCI PA	1,207	20	1,187	20	1,227
10			PECO Elec Dist-ARC EXP PA	(21)		(21)		(21)
11			PECO Electric 3611 PA	1,963	143	1,820	143	2,106
12			PECO Electric 3612 PA	2,983	145	2,838	145	3,127
13			PECO Electric 3613 PA	198	0	198	0	199
14			PECO Electric 3620 PA	25,211	1,006	24,205	1,006	26,217
15			PECO Electric 3640 PA	29,752	1,970	27,782	1,970	31,722
16			PECO Electric 3650 PA	45,704	2,455	43,249	2,455	48,159
17			PECO Electric 3660 PA	11,794	939	10,855	939	12,733
18			PECO Electric 3670 PA	41,404	2,435	38,969	2,435	43,840
19			PECO Electric 3680 PA	20,873	1,090	19,783	1,090	21,963
20			PECO Electric 3691 PA	4,008	154	3,854	154	4,162
21			PECO Electric 3692 PA	5,101	63	5,038	63	5,164
22			PECO Electric 3701 PA	188	12	176	12	201
23			PECO Electric 3710 PA	4		4		4
24			PECO Electric 3730 PA	820	22	798	22	842
25			PECO Electric 3731 PA	74	0	73	0	74
26			PECO Electric 3732 PA	1,072	46	1,026	46	1,117
27			PECO Electric 3733 PA	34		34		34
28			Sub-total Electric - Distribution	$228,191	$12,884	$215,307	$12,884	$241,075
29			Sub-total Electric - Distribution	$228,191	$12,884	$215,307	$12,884	$241,075
30								
31		Common - General Plant	PECO Common 3901 PA	$4,228	$43	$4,185	$43	$4,272
32			PECO Common 3902 IL	16		16		16
33			PECO Common 3902 PA	4,714	352	4,361	352	5,066
34			PECO Common 3903 PA	116	10	106	10	125
35			PECO Common 3911 PA	13		13		13
36			PECO Common 3912 PA	2,326	28	2,299	28	2,354
37			PECO Common 3913 IL	1,480	197	1,283	197	1,677
38			PECO Common 3913 PA	12,199	1,831	10,368	1,831	14,031
39			PECO Common 3930 PA	99	1	99	1	100
40			PECO Common 3941 PA	0		0		0
41			PECO Common 3942 PA	66		66		66
42			PECO Common 3970 PA	7,006	169	6,837	169	7,175

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
43			PECO Common 3980 PA	84		84		84
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	12		12		12
45			PECO Elec 3919 SM Comp Equip IL	24		24		24
46			PECO Elec 3919 SM Comp Equip MD	8		8		8
47			PECO Elec 3919 SM Comp Equip NC	5		5		5
48			PECO Elec 3919 SM Comp Equip PA	7		7		7
49			PECO Elec 3949 SM Tools PA	6		6		6
50			PECO Elec 3979 SM Comm Equip PA	2,606	24	2,582	24	2,630
51			PECO Electric 3901 PA	805	5	799	5	810
52			PECO Electric 3902 PA	402	3	399	3	406
53			PECO Electric 3903 PA	8		8		8
54			PECO Electric 3911 PA	0		0		0
55			PECO Electric 3912 PA	71	2	69	2	74
56			PECO Electric 3913 PA	5,468	141	5,327	141	5,609
57			PECO Electric 3930 PA	4		4		4
58			PECO Electric 3940 PA	3,891	147	3,744	147	4,038
59			PECO Electric 3951 PA	11		11		11
60			PECO Electric 3952 PA	0		0		0
61			PECO Electric 3970 PA	8,136	195	7,941	195	8,332
62			PECO Electric 3980 PA	84	6	78	6	90
63			Sub-total Electric - General Plant	$53,897	$3,156	$50,742	$3,156	$57,053
64			Sub-total Electric - General Plant	$53,897	$3,156	$50,742	$3,156	$57,053
65								
66		Electric - Transmission	PECO Electric 3521 PA	$398	$0	$398	$0	$398
67			PECO Electric 3522 MD	1		1		1
68			PECO Electric 3522 NJ	0		0		0
69			PECO Electric 3522 PA	1,719	33	1,686	33	1,753
70			PECO Electric 3523 NJ	0		0		0
71			PECO Electric 3523 PA	49		49		49
72			PECO Electric 3530 NJ	65		65		65
73			PECO Electric 3530 PA	19,515	279	19,236	279	19,795
74			PECO Electric 3540 DE	91		91		91
75			PECO Electric 3540 MD	52		52		52
76			PECO Electric 3540 NJ	216		216		216
77			PECO Electric 3540 PA	3,149	9	3,140	9	3,159
78			PECO Electric 3550 PA	596	20	577	20	616
79			PECO Electric 3560 DE	5		5		5
80			PECO Electric 3560 MD	12		12		12
81			PECO Electric 3560 NJ	154	4	150	4	157
82			PECO Electric 3560 PA	5,668	225	5,443	225	5,892
83			PECO Electric 3570 PA	1,157	77	1,079	77	1,234
84			PECO Electric 3580 PA	2,454	65	2,388	65	2,519

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
85			PECO Electric 3590 NJ	4		4		4
86			PECO Electric 3590 PA	28	1	28	1	29
87			Sub-total Electric - Transmission	$35,333	$713	$34,620	$713	$36,047
88								
89			Sub-total 403.0 Depreciation Expense	$317,421	$16,753	$300,668	$16,753	$334,175
90			Sub-total Electric - Transmission	$35,333	$713	$34,620	$713	$36,047
91								
92	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	$12,690	$36	$12,653	$36	$12,726
93			PECO - BIDA - Smart Energy Services	55	1	54	1	55
94			PECO - Distribution - ADMS	4,138	23	4,115	23	4,160
95			PECO - Distribution - IT	2,001	612	1,389	612	2,613
96			PECO - Transmission - IT	619	70	549	70	688
97			PECO Com 3030-Apollo SW	967		967		967
98			PECO Com 3030-BIDA Customer Project	130		130		130
99			PECO Com 3030-BIDA-AMI Ph2 SW	2,139		2,139		2,139
100			PECO Com 3030-CIS Transformation SW	120		120		120
101			PECO Com 3030-Cloud Serv 3 yr	6,069	169	5,901	169	6,238
102			PECO Com 3030-Cloud Serv 5 yr	2,585		2,585		2,585
103			PECO Com 3030-Common MDM SW	228		228		228
104			PECO Com 3030-EU Digital Program We	1,987		1,987		1,987
105			PECO Com 3030-EU oneMDS SW	5,269		5,269		5,269
106			PECO Com 3030-IT Cust Mobile App SW	111		111		111
107			PECO Com 3030-IVR System PA	159		159		159
109			PECO Com 3030-Misc 5 yr FR PA	9,884	2,098	7,787	2,098	11,982
110			PECO Com 3030-Misc 5 yr PA	60		60		60
111			PECO Com 3030-Mobile Dispatch Mappi	5,842		5,842		5,842
112			PECO Com 3030-OBIEE Migration SW	275		275		275
113			PECO Com 3030-PECO RNI Upgrade SW	(0)		(0)		(0)
114			PECO Elec 303 SM AMOS PA	111		111		111
115			PECO Elec 303-BIDA Grid T&D Domain	1,797		1,797		1,797
116			PECO Elec 303-CFP - Outage SW D	566		566		566
117			PECO Elec 303-EMS Implementation Pr	3,182		3,182		3,182
118			PECO Elec 303-EU Custom Analytics S	158		158		158
119			PECO Elec 303-EU Load Forecast SW	723		723		723
120			PECO Elec 303-EU Ratings DB SW D	12		12		12
121			PECO Elec 303-EU Ratings DB SW T	155		155		155
122			PECO Elec 303-EU TOA Implementation	395		395		395
123			PECO Elec 303-PECO RNI Upgrade SW D	591		591		591
124			PECO Elec 303-SES IV D SW	2,364		2,364		2,364
125			PECO Elec 3030-Cloud Serv 3 yr	32		32		32
126			PECO Elec 3030-Cloud Serv 5 yr	626		626		626
127			PECO Electric 303 Misc 5 FR PA	4,382		4,382		4,382

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
128			Sub-total Electric - Intangible Plant	$70,420	$3,007	$67,413	$3,007	$73,428
129								
130			Sub-total 404.0 Amort. of Limited-Term Electric Plant	$70,420	$3,007	$67,413	$3,007	$73,428
131								
132			**Total**	$387,842	$19,761	$368,081	$19,761	$407,603
133			Sub-total Electric - Intangible Plant	$70,420	$3,007	$67,413	$3,007	$73,428
134								
135			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.	$70,420	$3,007	$67,413	$3,007	$73,428

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$2,703	$357	$2,346	$357	$3,060
2			PECO Elec 3650 PA LTIIP	1.0000	4,037	440	3,597	440	4,478
3			PECO Elec 3660 PA LTIIP	1.0000	4,615	723	3,892	723	5,338
4			PECO Elec 3670 PA LTIIP	1.0000	6,084	764	5,320	764	6,847
5			PECO Elec 3705 SM UD RES PA	1.0000	9,577		9,577		9,577
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	2,210		2,210		2,210
7			PECO Elec 3707 SM RES PA	1.0000	5,764	96	5,668	96	5,861
8			PECO Elec 3708 SM SCI PA	1.0000	832	3	829	3	835
9			PECO Elec 3709 SM LCI PA	1.0000	1,207	20	1,187	20	1,227
10			PECO Elec Dist-ARC EXP PA	1.0000	(21)		(21)		(21)
11			PECO Electric 3611 PA	1.0000	1,963	143	1,820	143	2,106
12			PECO Electric 3612 PA	1.0000	2,983	145	2,838	145	3,127
13			PECO Electric 3613 PA	1.0000	198	0	198	0	199
14			PECO Electric 3620 PA	1.0000	25,211	1,006	24,205	1,006	26,217
15			PECO Electric 3640 PA	1.0000	29,752	1,970	27,782	1,970	31,722
16			PECO Electric 3650 PA	1.0000	45,704	2,455	43,249	2,455	48,159
17			PECO Electric 3660 PA	1.0000	11,794	939	10,855	939	12,733
18			PECO Electric 3670 PA	1.0000	41,404	2,435	38,969	2,435	43,840
19			PECO Electric 3680 PA	1.0000	20,873	1,090	19,783	1,090	21,963
20			PECO Electric 3691 PA	1.0000	4,008	154	3,854	154	4,162
21			PECO Electric 3692 PA	1.0000	5,101	63	5,038	63	5,164
22			PECO Electric 3701 PA	1.0000	188	12	176	12	201
23			PECO Electric 3710 PA	1.0000	4		4		4
24			PECO Electric 3730 PA	1.0000	820	22	798	22	842
25			PECO Electric 3731 PA	1.0000	74	0	73	0	74
26			PECO Electric 3732 PA	1.0000	1,072	46	1,026	46	1,117
27			PECO Electric 3733 PA	1.0000	34		34		34
28			Sub-total Electric - Distribution		$228,191	$12,884	$215,307	$12,884	$241,075
29			Sub-total Electric - Distribution		$228,191	$12,884	$215,307	$12,884	$241,075
30									
31		Common - General Plant	PECO Common 3901 PA	0.7693	$3,253	$33	$3,219	$33	$3,286
32			PECO Common 3902 IL	0.7693	12		12		12
33			PECO Common 3902 PA	0.7693	3,626	271	3,355	271	3,897
34			PECO Common 3903 PA	0.7693	89	7	81	7	96
35			PECO Common 3911 PA	0.7693	10		10		10
36			PECO Common 3912 PA	0.7693	1,790	21	1,768	21	1,811
37			PECO Common 3913 IL	0.7693	1,139	152	987	152	1,290
38			PECO Common 3913 PA	0.7693	9,385	1,409	7,976	1,409	10,794
39			PECO Common 3930 PA	0.7693	77	1	76	1	77
40			PECO Common 3941 PA	0.7693	0		0		0
41			PECO Common 3942 PA	0.7693	51		51		51
42			PECO Common 3970 PA	0.7693	5,390	130	5,260	130	5,520

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
43			PECO Common 3980 PA	0.7693	65		65		65
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	1.0000	12		12		12
45			PECO Elec 3919 SM Comp Equip IL	1.0000	24		24		24
46			PECO Elec 3919 SM Comp Equip MD	1.0000	8		8		8
47			PECO Elec 3919 SM Comp Equip NC	1.0000	5		5		5
48			PECO Elec 3919 SM Comp Equip PA	1.0000	7		7		7
49			PECO Elec 3949 SM Tools PA	1.0000	6		6		6
50			PECO Elec 3979 SM Comm Equip PA	1.0000	2,606	24	2,582	24	2,630
51			PECO Electric 3901 PA	1.0000	805	5	799	5	810
52			PECO Electric 3902 PA	1.0000	402	3	399	3	406
53			PECO Electric 3903 PA	1.0000	8		8		8
54			PECO Electric 3911 PA	1.0000	0		0		0
55			PECO Electric 3912 PA	1.0000	71	2	69	2	74
56			PECO Electric 3913 PA	1.0000	5,468	141	5,327	141	5,609
57			PECO Electric 3930 PA	1.0000	4		4		4
58			PECO Electric 3940 PA	1.0000	3,891	147	3,744	147	4,038
59			PECO Electric 3951 PA	1.0000	11		11		11
60			PECO Electric 3952 PA	1.0000	0		0		0
61			PECO Electric 3970 PA	1.0000	8,136	195	7,941	195	8,332
62			PECO Electric 3980 PA	1.0000	84	6	78	6	90
63			Sub-total Electric - General Plant		$46,434	$2,549	$43,886	$2,549	$48,983
64			Sub-total Electric - General Plant		$46,434	$2,549	$43,886	$2,549	$48,983
65									
66		Electric - Transmission	PECO Electric 3521 PA	1.0000	$398	$0	$398	$0	$398
67			PECO Electric 3522 MD	1.0000	1		1		1
68			PECO Electric 3522 NJ	1.0000	0		0		0
69			PECO Electric 3522 PA	1.0000	1,719	33	1,686	33	1,753
70			PECO Electric 3523 NJ	1.0000	0		0		0
71			PECO Electric 3523 PA	1.0000	49		49		49
72			PECO Electric 3530 NJ	1.0000	65		65		65
73			PECO Electric 3530 PA	1.0000	19,515	279	19,236	279	19,795
74			PECO Electric 3540 DE	1.0000	91		91		91
75			PECO Electric 3540 MD	1.0000	52		52		52
76			PECO Electric 3540 NJ	1.0000	216		216		216
77			PECO Electric 3540 PA	1.0000	3,149	9	3,140	9	3,159
78			PECO Electric 3550 PA	1.0000	596	20	577	20	616
79			PECO Electric 3560 DE	1.0000	5		5		5
80			PECO Electric 3560 MD	1.0000	12		12		12
81			PECO Electric 3560 NJ	1.0000	154	4	150	4	157
82			PECO Electric 3560 PA	1.0000	5,668	225	5,443	225	5,892
83			PECO Electric 3570 PA	1.0000	1,157	77	1,079	77	1,234
84			PECO Electric 3580 PA	1.0000	2,454	65	2,388	65	2,519

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
85			PECO Electric 3590 NJ	1.0000	4		4		4
86			PECO Electric 3590 PA	1.0000	28	1	28	1	29
87			Sub-total Electric - Transmission		$35,333	$713	$34,620	$713	$36,047
88									
89			Sub-total 403.0 Depreciation Expense		$309,959	$16,146	$293,813	$16,146	$326,105
90			Sub-total Electric - Transmission		$35,333	$713	$34,620	$713	$36,047
91									
92	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	0.7450	$9,454	$27	$9,427	$27	$9,481
93			PECO - BIDA - Smart Energy Services	1.0000	55	1	54	1	55
94			PECO - Distribution - ADMS	1.0000	4,138	23	4,115	23	4,160
95			PECO - Distribution - IT	1.0000	2,001	612	1,389	612	2,613
96			PECO - Transmission - IT	1.0000	619	70	549	70	688
97			PECO Com 3030-Apollo SW	0.7693	744		744		744
98			PECO Com 3030-BIDA Customer Project	0.7693	100		100		100
99			PECO Com 3030-BIDA-AMI Ph2 SW	0.7693	1,645		1,645		1,645
100			PECO Com 3030-CIS Transformation SW	0.7693	92		92		92
101			PECO Com 3030-Cloud Serv 3 yr	0.7693	4,669	130	4,539	130	4,799
102			PECO Com 3030-Cloud Serv 5 yr	0.7693	1,989		1,989		1,989
103			PECO Com 3030-Common MDM SW	0.7693	176		176		176
104			PECO Com 3030-EU Digital Program We	0.7693	1,529		1,529		1,529
105			PECO Com 3030-EU oneMDS SW	0.7693	4,053		4,053		4,053
106			PECO Com 3030-IT Cust Mobile App SW	0.7693	85		85		85
107			PECO Com 3030-IVR System PA	0.7693	122		122		122
109			PECO Com 3030-Misc 5 yr FR PA	0.7693	7,604	1,614	5,990	1,614	9,218
110			PECO Com 3030-Misc 5 yr PA	0.7693	46		46		46
111			PECO Com 3030-Mobile Dispatch Mappi	0.7693	4,494		4,494		4,494
112			PECO Com 3030-OBIEE Migration SW	0.7693	212		212		212
113			PECO Com 3030-PECO RNI Upgrade SW	0.7693	(0)		(0)		(0)
114			PECO Elec 303 SM AMOS PA	1.0000	111		111		111
115			PECO Elec 303-BIDA Grid T&D Domain	1.0000	1,797		1,797		1,797
116			PECO Elec 303-CFP - Outage SW D	1.0000	566		566		566
117			PECO Elec 303-EMS Implementation Pr	1.0000	3,182		3,182		3,182
118			PECO Elec 303-EU Custom Analytics S	1.0000	158		158		158
119			PECO Elec 303-EU Load Forecast SW	1.0000	723		723		723
120			PECO Elec 303-EU Ratings DB SW D	1.0000	12		12		12
121			PECO Elec 303-EU Ratings DB SW T	1.0000	155		155		155
122			PECO Elec 303-EU TOA Implementation	1.0000	395		395		395
123			PECO Elec 303-PECO RNI Upgrade SW D	1.0000	591		591		591
124			PECO Elec 303-SES IV D SW	1.0000	2,364		2,364		2,364
125			PECO Elec 3030-Cloud Serv 3 yr	1.0000	32		32		32
126			PECO Elec 3030-Cloud Serv 5 yr	1.0000	626		626		626
127			PECO Electric 303 Misc 5 FR PA	1.0000	4,382		4,382		4,382

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
128			Sub-total Electric - Intangible Plant		$58,920	$2,475	$56,445	$2,475	$61,395
129									
130			Sub-total 404.0 Amort. of Limited-Term Electric Plant		$58,920	$2,475	$56,445	$2,475	$61,395
131									
132			**Total**		$368,879	$18,621	$350,257	$18,621	$387,500
133			Sub-total Electric - Intangible Plant		$58,920	$2,475	$56,445	$2,475	$61,395
134									
135			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.		$58,920	$2,475	$56,445	$2,475	$61,395

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
1	403.0 Depreciation Expense.	Electric - Distribution	PECO Elec 3640 PA LTIIP	1.0000	$2,703	$357	$2,346	$357	$3,060
2			PECO Elec 3650 PA LTIIP	1.0000	$4,037	440	3,597	440	4,478
3			PECO Elec 3660 PA LTIIP	1.0000	$4,615	723	3,892	723	5,338
4			PECO Elec 3670 PA LTIIP	1.0000	$6,084	764	5,320	764	6,847
5			PECO Elec 3705 SM UD RES PA	1.0000	$9,577		9,577		9,577
6			PECO Elec 3706 Non DOE Rcv PA	1.0000	$2,210		2,210		2,210
7			PECO Elec 3707 SM RES PA	1.0000	$5,764	96	5,668	96	5,861
8			PECO Elec 3708 SM SCI PA	1.0000	$832	3	829	3	835
9			PECO Elec 3709 SM LCI PA	1.0000	$1,207	20	1,187	20	1,227
10			PECO Elec Dist-ARC EXP PA						
11			PECO Electric 3611 PA	1.0000	$1,963	143	1,820	143	2,106
12			PECO Electric 3612 PA	1.0000	$2,983	145	2,838	145	3,127
13			PECO Electric 3613 PA	1.0000	$198	0	198	0	199
14			PECO Electric 3620 PA	1.0000	$25,211	1,006	24,205	1,006	26,217
15			PECO Electric 3640 PA	1.0000	$29,752	1,970	27,782	1,970	31,722
16			PECO Electric 3650 PA	1.0000	$45,704	2,455	43,249	2,455	48,159
17			PECO Electric 3660 PA	1.0000	$11,794	939	10,855	939	12,733
18			PECO Electric 3670 PA	1.0000	$41,404	2,435	38,969	2,435	43,840
19			PECO Electric 3680 PA	1.0000	$20,873	1,090	19,783	1,090	21,963
20			PECO Electric 3691 PA	1.0000	$4,008	154	3,854	154	4,162
21			PECO Electric 3692 PA	1.0000	$5,101	63	5,038	63	5,164
22			PECO Electric 3701 PA	1.0000	$188	12	176	12	201
23			PECO Electric 3710 PA	1.0000	$4		4		4
24			PECO Electric 3730 PA	1.0000	$820	22	798	22	842
25			PECO Electric 3731 PA	1.0000	$74	0	73	0	74
26			PECO Electric 3732 PA	1.0000	$1,072	46	1,026	46	1,117
27			PECO Electric 3733 PA	1.0000	$34		34		34
28			Sub-total Electric - Distribution		$228,212	$12,884	$215,328	$12,884	$241,096
29			Sub-total Electric - Distribution		$228,212	$12,884	$215,328	$12,884	$241,096
30									
31		Common - General Plant	PECO Common 3901 PA	0.8763	$2,850	$29	$2,821	$29	$2,879
32			PECO Common 3902 IL	0.8763	11		11		11
33			PECO Common 3902 PA	0.8763	3,177	238	2,940	238	3,415
34			PECO Common 3903 PA	0.8763	78	7	71	7	84
35			PECO Common 3911 PA	0.8763	8		8		8
36			PECO Common 3912 PA	0.8763	1,568	19	1,549	19	1,587
37			PECO Common 3913 IL	0.8763	998	133	865	133	1,131
38			PECO Common 3913 PA	0.8763	8,224	1,234	6,989	1,234	9,458
39			PECO Common 3930 PA	0.8763	67	0	67	0	68
40			PECO Common 3941 PA	0.8763	0		0		0
41			PECO Common 3942 PA	0.8763	45		45		45
42			PECO Common 3970 PA	0.8763	4,723	114	4,609	114	4,837

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
43			PECO Common 3980 PA	0.8763	57		57		57
44		Electric - General Plant	PECO Elec 3919 SM Comp Equip ID	0.8763	11		11		11
45			PECO Elec 3919 SM Comp Equip IL	0.8763	21		21		21
46			PECO Elec 3919 SM Comp Equip MD	0.8763	7		7		7
47			PECO Elec 3919 SM Comp Equip NC	0.8763	4		4		4
48			PECO Elec 3919 SM Comp Equip PA	0.8763	7		7		7
49			PECO Elec 3949 SM Tools PA	0.8763	6		6		6
50			PECO Elec 3979 SM Comm Equip PA	0.8763	2,283	21	2,263	21	2,304
51			PECO Electric 3901 PA	0.8763	705	5	700	5	710
52			PECO Electric 3902 PA	0.8763	353	3	349	3	356
53			PECO Electric 3903 PA	0.8763	7		7		7
54			PECO Electric 3911 PA	0.8763	0		0		0
55			PECO Electric 3912 PA	0.8763	63	2	60	2	65
56			PECO Electric 3913 PA	0.8763	4,791	123	4,668	123	4,915
57			PECO Electric 3930 PA	0.8763	3		3		3
58			PECO Electric 3940 PA	0.8763	3,410	129	3,281	129	3,538
59			PECO Electric 3951 PA	0.8763	10		10		10
60			PECO Electric 3952 PA	0.8763	0		0		0
61			PECO Electric 3970 PA	0.8763	7,129	171	6,958	171	7,301
62			PECO Electric 3980 PA	0.8763	74	5	68	5	79
63			Sub-total Electric - General Plant		$40,689	$2,233	$38,456	$2,233	$42,922
64			Sub-total Electric - General Plant		$40,689	$2,233	$38,456	$2,233	$42,922
65									
66		Electric - Transmission	PECO Electric 3521 PA						
67			PECO Electric 3522 MD						
68			PECO Electric 3522 NJ						
69			PECO Electric 3522 PA						
70			PECO Electric 3523 NJ						
71			PECO Electric 3523 PA						
72			PECO Electric 3530 NJ						
73			PECO Electric 3530 PA						
74			PECO Electric 3540 DE						
75			PECO Electric 3540 MD						
76			PECO Electric 3540 NJ						
77			PECO Electric 3540 PA						
78			PECO Electric 3550 PA						
79			PECO Electric 3560 DE						
80			PECO Electric 3560 MD						
81			PECO Electric 3560 NJ						
82			PECO Electric 3560 PA						
83			PECO Electric 3570 PA						
84			PECO Electric 3580 PA						

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
85			PECO Electric 3590 NJ						
86			PECO Electric 3590 PA						
87			Sub-total Electric - Transmission						
88									
89			Sub-total 403.0 Depreciation Expense		$268,901	$15,117	$253,783	$15,117	$284,018
90			Sub-total Electric - Transmission						
91									
92	404.0 Amort. Of Limited-Term Electric Plant.	Electric - Intangible Plant	FDG_PECO_C_CIMS:PECO - Common - CIMS	1.0000	$9,454	$27	$9,427	$27	$9,481
93			PECO - BIDA - Smart Energy Services	1.0000	55	1	54	1	55
94			PECO - Distribution - ADMS	0.8763	3,626	20	3,606	20	3,646
95			PECO - Distribution - IT	0.8763	1,753	536	1,217	536	2,289
96			PECO - Transmission - IT	0.8763	542	61	481	61	603
97			PECO Com 3030-Apollo SW	0.8763	652		652		652
98			PECO Com 3030-BIDA Customer Project	0.8763	88		88		88
99			PECO Com 3030-BIDA-AMI Ph2 SW	0.8763	1,442		1,442		1,442
100			PECO Com 3030-CIS Transformation SW	0.8763	81		81		81
101			PECO Com 3030-Cloud Serv 3 yr	0.8763	4,092	114	3,978	114	4,205
102			PECO Com 3030-Cloud Serv 5 yr	0.8763	1,743		1,743		1,743
103			PECO Com 3030-Common MDM SW	0.8763	154		154		154
104			PECO Com 3030-EU Digital Program We	0.8763	1,340		1,340		1,340
105			PECO Com 3030-EU oneMDS SW	0.8763	3,552		3,552		3,552
106			PECO Com 3030-IT Cust Mobile App SW	0.8763	75		75		75
107			PECO Com 3030-IVR System PA	0.8763	107		107		107
109			PECO Com 3030-Misc 5 yr FR PA	0.8763	6,663	1,414	5,249	1,414	8,077
110			PECO Com 3030-Misc 5 yr PA	0.8763	40		40		40
111			PECO Com 3030-Mobile Dispatch Mappi	0.8763	3,938		3,938		3,938
112			PECO Com 3030-OBIEE Migration SW	0.8763	186		186		186
113			PECO Com 3030-PECO RNI Upgrade SW	0.8763	(0)		(0)		(0)
114			PECO Elec 303 SM AMOS PA	1.0000	111		111		111
115			PECO Elec 303-BIDA Grid T&D Domain	0.8763	1,574		1,574		1,574
116			PECO Elec 303-CFP - Outage SW D	1.0000	566		566		566
117			PECO Elec 303-EMS Implementation Pr						
118			PECO Elec 303-EU Custom Analytics S	1.0000	158		158		158
119			PECO Elec 303-EU Load Forecast SW	1.0000	723		723		723
120			PECO Elec 303-EU Ratings DB SW D	1.0000	12		12		12
121			PECO Elec 303-EU Ratings DB SW T						
122			PECO Elec 303-EU TOA Implementation						
123			PECO Elec 303-PECO RNI Upgrade SW D	1.0000	591		591		591
124			PECO Elec 303-SES IV D SW	1.0000	2,364		2,364		2,364
125			PECO Elec 3030-Cloud Serv 3 yr	0.8763	28		28		28
126			PECO Elec 3030-Cloud Serv 5 yr	0.8763	549		549		549
127			PECO Electric 303 Misc 5 FR PA	0.8763	3,839		3,839		3,839

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
128			Sub-total Electric - Intangible Plant		$50,096	$2,172	$47,924	$2,172	$52,269
129									
130			Sub-total 404.0 Amort. of Limited-Term Electric Plant		$50,096	$2,172	$47,924	$2,172	$52,269
131									
132			**Total**		$318,997	$17,290	$301,707	$17,290	$336,287
133			Sub-total Electric - Intangible Plant		$50,096	$2,172	$47,924	$2,172	$52,269
134									
135			Sub-total 404.0 Amort. Of Limited-Term Electric Plant.		$50,096	$2,172	$47,924	$2,172	$52,269

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UPDATE 07-16-24

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$2,908,221	$464,202	$3,372,423
2	Operating Expenses		2,532,993	32,907	2,565,900
3	OIBIT	L1 - L2	$375,228	$431,294	$806,522
4					
5	Rate Base		$8,855,613		$8,855,613
6	Weighted Cost of Debt		2.130%		2.130%
7	Synchronized Interest Expense	L5 * L6	$188,625		$188,625
8	Base Taxable Income	L3 - L7	$186,603	$431,294	$617,898
9					
10	State Accelerated Tax Depreciation		$367,105		$367,105
11	Pro Forma Book Depreciation		336,287		336,287
12	State Tax Depreciation (Over) Under Book	L11 - L10	($30,819)		($30,819)
13	Regulatory Asset Programs M-1, Pension and Post Retirement & Other		(24,323)		(24,323)
14	Other Property Basis Adjustments (CIAC/ICM)		(58,325)		(58,325)
15	Removal Costs/Software		(7,598)		(7,598)
16	AFUDC Equity		(26,536)		(26,536)
17	Permanent Adjustments		4,315		4,315
18	Repair Deduction		(210,100)		(210,100)
19					
20	State Taxable Income	L8 + SUM (L12 to L18)	($166,782)	$431,294	$264,513
21					
22	State Income Tax Rate		7.99%	7.99%	7.99%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L22 * L20)	$13,326	($34,460)	($21,135)
24	Net Operating Loss Utilization %		40.00%	40.00%	40.00%
25	Net Operating Loss Utilization	- L24 * L23	(5,330)	13,784	8,454
26	State Income Tax Benefit / (Expense)	L23 + L25	$7,996	($20,676)	($12,681)
27					
28	Federal Accelerated Tax Depreciation		$357,203		$357,203
29	Pro Forma Book Depreciation		336,287		336,287
30	Federal Tax Deducts (Over) Under Book	L29 - L28	($20,916)		($20,916)
31	Regulatory Asset Programs M-1		(24,323)		(24,323)
32	Other Property Basis Adjustments (CIAC/ICM)		(58,325)		(58,325)
33	Removal Costs/Software		(7,598)		(7,598)
34	AFUDC Equity		(26,536)		(26,536)
35	Permanent Adjustments		4,315		4,315
36	Repair Deduction		(210,100)		(210,100)
37	Federal NOL				
38	Federal Taxable Income	L8 + L26 + SUM (L30 to L37)	($148,884)	$410,618	$261,735
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	-	$31,266	($86,230)	($54,964)
42	Corporate Alternative Minimum Tax		($45,820)		($45,820)
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	($6,559)	($106,906)	($113,465)
44					

Line No.	Description	Reference	Present Rates	Rate Increase	Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($23,076)	$2,895	($20,182)
47	Deferred Taxes on Timing Differences- State		(6,604)		(6,604)
48	Deferred Taxes on State NOL		5,330	(13,784)	(8,454)
49	Excess Deferred Amortization		6,987		6,987
50	Excess Deferred Amortization - State (Net of Federal)		232		232
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax Expense on Flow Through Adjustment		(4,194)		(4,194)
53	Corporate Alternative Minimum Tax		45,820		45,820
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	$24,496	($10,889)	$13,606
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	$17,937	($117,796)	($99,859)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		$15		$15
60					
61	Combined Income Tax Benefit / (Expense)	SUM L56 to L59	$17,951	($117,796)	($99,844)
62					
63	**Federal Income Tax Benefit / (Expense)**	L41 + L46 + L49 + L51 + L52 + L59	**$10,997**	**($83,335)**	**($72,338)**
64	**State Income Tax Benefit / (Expense)**	L26 + L47 + L48 + L50	**$6,954**	**($34,460)**	**($27,506)**
65	**Total Income Tax Benefit / (Expense)**	L63 + L64	**$17,951**	**($117,796)**	**($99,844)**

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Reference	2018	2019	2020	2021	2022	Average
1	PECO Consolidated Taxable Income		$149,524	$191,310	($22,448)	$33,306	$135,993	
2								
3								
4	Consolidated Income Companies Taxable Income		$1,005,422	$931,575	$937,098	$1,705,766	$816,851	
5								
6								
7	Taxable Income Percentage to PECO	L1 / L4	14.87%	20.54%		1.95%	16.65%	
8								
9								
10	Consolidated Companies Loss		$ (85,736)	$ (162,524)	$ (249,053)	$ (575,746)	$ (108,853)	
11								
12								
13	PECO Allocation of Loss	L7 * L10	$ (12,750)	$ (33,376)	$ -	$ (11,242)	$ (18,122)	
14								
15								
16	Electric Percentage		106.61%	125.46%	-88.07%	376.30%	158.98%	
17								
18								
19	Loss Allocable to Electric	L13 * L16	($13,593)	($41,874)		($42,303)	($28,809)	
20								
21								
22								
23	Average for 2018 to 2022	Average L19						(25,316)
24								
25								
26	Tax Rate							21.00%
27								
28	**Section 1301.1(b) Differential**	L23 * L26						**$ (5,316)**

		(1)	(2)
Line No.	Description	Reference	Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		12,224
4	Total Customer Revenue		2,949,296
5	Shopping Revenue		1,082,504
6	LPC REVENUE	L3 / (L4 + L5)	0.003032
7	GROSS RECEIPTS TAX		(0.059000)
8	UNCOLLECTIBLE EXPENSES	D-10	(0.009708)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.002397)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.931927
13			
14	STATE INCOME TAX RATE		7.990%
15			
16	STATE INCOME TAX FACTOR	-	(0.074461)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.857466
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	-	(0.180068)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.677398
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.476236
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	25.453%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		7.990%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.079900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.920100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.193221)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.726879
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.375745
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	27.312%

PECO ENERGY COMPANY
STATEMENT NO. 3-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

REBUTTAL TESTIMONY

WITNESS: MICHAEL J. TRZASKA

SUBJECT: PRESENTING PECO ENERGY COMPANY'S UPDATED OVERALL REVENUE REQUIREMENT; RESPONSE TO CERTAIN OPPOSING PARTY ADJUSTMENTS; STORM RESERVE ACCOUNT; RECOVERY OF CUSTOMER ASSISTANCE PROGRAM COSTS

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
MICHAEL J. TRZASKA

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Michael J. Trzaska. I am employed by PECO Energy Company ("PECO" or the "Company") as a Principal Regulatory and Rate Specialist. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct testimony marked as PECO Statement No. 3. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. First, I describe the changes PECO is making to the revenue requirement previously presented in PECO Exhibit MJT-1 in order to reflect (a) more recent data or the Company's revised position on certain issues, as previously set forth in interrogatory responses and (b) the Company's decision to adopt certain adjustments proposed by the active parties. Second, I respond to various portions of the direct testimony regarding rate base, revenue, and expense claims presented by Bureau of Investigation and Enforcement ("I&E") witness Christine Wilson and Office of Consumer Advocate ("OCA") witness John Defever. Third, I address objections to PECO's proposed Storm Reserve Account raised by I&E witness Wilson and OCA witness Defever. Finally, I respond to the direct testimony of OCA witness Roger D. Colton regarding the offset factor applied to

reconcilable Customer Assistance Program ("CAP") costs recovered through PECO's Universal Service Fund Charge ("USFC").

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

A. Yes. I will describe those exhibits during the course of my update and response to the other parties.

II. UPDATE OF THE COMPANY'S REVENUE REQUIREMENT

5. Q. As developed in your testimony, what is PECO's updated Fully Projected Future Test Year ("FPFTY") revenue requirement?

A. PECO's updated FPFTY revenue requirement, as shown in PECO Exhibit MJT-1 Revised, Schedule A-1, is $462.8 million, which translates into updated pro forma present rate revenue of $1.789 million. This represents an approximate $0.8 million reduction to PECO's initial increase request of $463.6 million.

6. Q. Please describe PECO Exhibit MJT-1 Revised.

A. PECO Exhibit MJT-1 Revised is an update of PECO Exhibit MJT-1. The schedules that are included with PECO Exhibit MJT-1 Revised are updated versions of the original schedules included with PECO Exhibit MJT-1. Pages that have been updated from the original schedules are marked "UPDATE 07-16-2024." PECO Exhibit MJT-1 Revised reflects a few revisions that affect the Company's revenue requirement claim as described later in my rebuttal testimony.

7. Q. Please summarize the revisions to the Company's revenue requirement claims reflected in PECO Exhibit MJT-1 Revised.

A. PECO Exhibit MJT-1 Revised reflects two revisions that affect the Company's revenue requirement claim. First, as I explain in more detail later in my rebuttal testimony, PECO is updating its claim for normalized storm expenses to substitute actual storm costs incurred in the first quarter of 2024 for the estimated data reflected in the Company's original filing. As a result of this update, the Company's normalized storm expense, which is based on inflation-adjusted storm expenses for the 60-month period ended March 31, 2024, is reduced by $0.8 million, and its revenue requirement is reduced by $0.8 million.

Second, in response to concerns expressed by Mr. Colton in his direct testimony, PECO is updating its proposed change to the negotiated USFC formula offset percentages established in the Commission-approved settlement of PECO's first default service proceeding at Docket No. P-2008-2062739 (the "DSP Settlement") for uncollectible expense (22%) and cash working capital ("CWC") (5%). As discussed later in my testimony, PECO proposes to maintain the 5% USFC offset factor for CWC using current data in the same methodology recommended by Mr. Colton in PECO's 2008 gas rate case (Docket R-2008-2028394), which was the basis for calculating the 5% working capital adjustment adopted in the DSP Settlement. In addition, as explained by Company witness Jacqueline F. Golden in her rebuttal testimony (PECO Statement No. 10-R), PECO is revising its recommended USFC offset percentage for uncollectible expense from 5.5% to 7.1%. In total, PECO's updated proposal for the USFC offset factor is 12.1%, which represents a 1.6% increase from the Company's original proposal of

10.5%. The net impact of this change is a $32,000 reduction in PECO's revenue requirement.

III. RESPONSE TO OPPOSING PARTY ADJUSTMENTS

A. FPFTY Plant-In-Service Additions

8. Q. I&E witness Sakaya recommends that the Company provide I&E and the OCA with updates on plant additions that PECO projects to be in service during the Future Test Year ("FTY") and FPFTY, as follows (i) an update to PECO Exhibit MJT-2, Schedule C-2, no later than April 1, 2025, which should include plant additions, retirements, and reclassifications by month from January 1, 2024 through December 31, 2024; and (ii) and an update to PECO Exhibit MJT-1, Schedule C-2, no later than April 1, 2026, which should include plant additions, retirements, and reclassifications by month from January 1, 2025 through December 31, 2025. Will the Company provide the requested information?

A. Yes. The Company agrees that this request is reasonable and will provide the requested information in a timely manner.

B. Act 129 Usage Differential

9. Q. Please describe the Company's proposed pro forma revenue adjustment arising from the Company's compliance with Act 129 of 2008 ("Act 129").

A. As I explained in my direct testimony (PECO Statement No. 3, pp. 35-36), the Company is proposing a pro forma revenue adjustment to its FPFTY budgeted revenue of $3.8 million to allow PECO to recover its lost revenue for 2026 through the rates established in this proceeding.

10. Q. Please address Mr. Sakaya's proposed adjustment regarding revenue lost as a result of Act 129 load reductions.

A. Mr. Sakaya recommends a rejection of the Company's pro forma revenue adjustment in its entirety. Mr. Sakaya asserts it is not reasonable to go beyond the FPFTY and reflect revenue decline that may occur for up to two years in the future on the first day rates become effective (i.e., December 31, 2024) since, in his opinion, it would result in the Company over-collecting revenue until the end of 2026.

11. Q. Please respond to Mr. Sakaya's recommendation.

A. As I noted in my direct testimony, Act 129 specifically contemplates that revenue reductions attributable to the mandated energy efficiency programs be taken into account in establishing base rates. It would be unfair and unreasonable to require PECO to implement these programs, or be subjected to possible penalties for non-compliance with legislatively imposed energy-reduction goals, and then deny the Company rate recovery of the lost revenues, particularly given the tremendous benefits to customers. Compliance with Act 129 will result in load reductions in furtherance of the Legislature's and the Commission's energy-reduction goals, but will also result in lost revenue, which the Legislature has also determined utilities should be entitled to. This will not result in an over-recovery prior to 2026 since PECO's revenue losses in that year are known, measurable, and independently verified by an unbiased third-party evaluator as they have been approved by the Commission in the context of PECO's Act 129 proceeding.

12. Q. Does Mr. Sakaya dispute that Act 129's legislative mandate requires PECO

to achieve actual usage reductions in 2026 in the amounts PECO has used to calculate its claim for lost revenues in that year?

A. No. And, I do not believe there is any basis for such a dispute, in any event. Section 2806.1(c), which was added to the Pennsylvania Public Utility Code by Act 129, requires the Commission to establish "additional required incremental reductions" for the major electric distribution companies ("EDCs"). In its Implementation Order entered on June 18, 2020, the Commission set a usage reduction target for PECO of 1,380,837 MWh, for the Phase IV EE&C period, which extends from June 1, 2021 to May 31, 2026.[1] In doing so, the Commission adopted the findings of its Statewide Evaluator ("SWE") that the EE&C measures necessary to produce that level of usage reduction are cost-effective (i.e., will produce benefits that exceed costs), as measured by a Commission-approved Total Resource Cost test. Moreover, the metrics for determining such reductions and measuring PECO's compliance with the Commission-established usage reductions have also been established by the Commission. Finally, if PECO does not achieve the Commission-established usage reductions, measured on the basis of its approved metrics, the Company faces penalties for non-compliance between $1 million and $20 million, as set forth in Section 2806.1(f)(2)(i).

Given the legislative and regulatory mandates for usage reductions, which must be measured on the basis of Commission-approved metrics, and the knowledge that non-compliance will result in a significant penalty to PECO, there is no

[1] *Energy Efficiency and Conservation Program*, Docket No. M-2020-3015228 (Implementation Order entered June 18, 2020), p. 8 (Table 2).

question that the usage reductions the Company has reflected are known and measurable.

13. Q. What is PECO's track record when it comes to achieving Commission-mandated usage reductions?

A. PECO has a well-established track record of aggressively and successfully implementing its EE&C programs. In fact, PECO has been a strong advocate for advancing energy efficiency and has won multiple awards for its "Smart Ideas" energy efficiency programs. PECO is committed to the success of its existing Phase IV EE&C programs and to providing customers the significant benefits that the SWE has forecasted for those programs.

14. Q. Why is PECO's aggressive pursuit of EE&C measures relevant to this issue?

A. PECO's strong commitment to delivering to customers the benefits of its EE&C programs should be matched by the Commission's authorization of a reasonable opportunity for PECO to recover the full range of costs it incurs to create those benefits. PECO is currently incurring approximately $80 million per year in direct program implementation costs for its Phase IV EE&C program. However, those costs do not reflect PECO's lost revenues due to usage reductions that must be achieved to comply with Act 129's and the Commission's ordered usage reduction mandates. With respect to both the direct costs of implementing its EE&C programs and the revenue losses that will necessarily flow from the success of those programs, PECO is not seeking any margin or profit; it is simply seeking a reasonable opportunity for cost recovery.

15. Q. What does Section 2806.1, which was added to the Public Utility Code by Act 129, provide with regard to reflecting EE&C costs and decreased revenues in an EDC's rates?

A. Section 2806.1(k)(1) allows an EDC to "recover on a full and current basis from customers, through a reconcilable adjustment clause under section 1307, all reasonable and prudent costs incurred in the provision or management of a plan provided under this section." Section 2806.1(k)(2), in turn, provides that "decreased revenues of an electric distribution company due to reduced energy consumption or changes in energy demand shall not be a recoverable cost under a reconcilable automatic adjustment clause." However, in recognition of the prohibition on Section 1307 recovery of decreased revenues, Section 2806.1(k)(3) provides as follows:

> Decreased revenue and reduced energy consumption may be reflected in revenue and sales data used to calculate rates in a distribution-base rate proceeding filed by an electric distribution company under section 1308 (relating to voluntary changes in rates).

16. Q. Mr. Sakaya contends that reductions in customer usage caused by PECO's obligation to comply with the mandates of Act 129 and the Commission's orders issued pursuant to that Act should not be reflected in this case for any period beyond the end of the FPFTY. Do you agree?

A. No. While I am not a lawyer and am not providing a legal interpretation of the statutory language, I will discuss several important factors that must be considered in deciding what constitutes a reasonable approach to reflecting decreased revenues in an EDC's base rates.

First, Mr. Sakaya appears to contend that the relevant statutory language (i.e., "may be reflected in revenue and sales data used to calculate rates in a distribution base rate proceeding") must mean that usage reductions occurring beyond the test year an EDC employs in a base rate case should not be considered in setting that EDC's base rates in that case. His position is not reasonable. While the legal interpretation of Section 2806.1(k)(3) will be addressed in the parties' briefs, it would appear unnecessary to add language to the Public Utility Code to specifically authorize the filing of another rate case for periods after the test year. In other words, it makes sense that the language "may be reflected in revenue and sales data used to calculate rates in a distribution-base rate proceeding" allows an EDC to do more than continue what pre-existing Commission practice would have permitted and, therefore, reductions in usage certain to occur when an EDC's rates are in effect should be taken into account in setting those rates.

Second, and closely related to my first point, above, the "decreased revenues" that will occur after the end of a test year employed in a base rate case are a product of a legislative mandate and Commission orders implementing those statutory requirements. In other words, an EDC will experience revenues that unquestionably will be lower than they otherwise would be, and that reduction is the direct result of a government mandate. Consequently, if the Commission were to "calculate rates in a distribution base rate case" without recognizing the effects of EE&C measures that are certain to produce incremental reductions in customer usage in periods after the end of the test year, the rates established by the

Commission will not produce the revenues that were assumed as the basis for setting those rates. Simply stated, the Commission would be setting rates on the basis of a future scenario that embodies a known error, specifically, an overstated level of customer usage.

In this regard, it is significant that the Company has proposed normalizing its rate case expenses over two years as a period that is reasonably predictive of how long the rates established in this case will remain in effect. The usage reductions that will occur during 2026, which the Company proposes to recognize, are within the period that rates established in this case would most likely remain in effect.

Third, while setting rates on the basis of sales levels that overstate future customer usage is not a fair or reasonable outcome under any circumstances, it is particularly inappropriate where: (1) the future usage reductions are required by governmental mandate; and (2) the EDC must comply with that mandate or be subject to penalties of between $1 million and $20 million. This is not a situation where one of several contingent future events is singled out as the basis for adjusting sales levels. PECO must achieve the level of usage reductions specified by the Commission or face severe penalties for non-compliance. At the same time, under the approach advocated by I&E, PECO's diligent, good-faith compliance with the Commission's mandate would nonetheless subject it to a financial penalty of nearly equal magnitude by denying it a reasonable opportunity to reflect known and measurable usage reductions directly caused by that governmental mandate. It would not be fair or reasonable for the Legislature (or the Commission) to put EDCs in this "lose/lose" situation – fail to comply

with Act 129's mandate and face a penalty or fully comply with that mandate and still face a penalty of substantial revenue decreases that are not reflected in setting base rates.

C. Payroll Expense

17. Q. Please respond to I&E witness Wilson's and OCA witness Defever's removal of PECO's annualization adjustment for annual pay increases effective January 1, 2026 and March 1, 2026.

A. The Company's salary and wage ("S&W") increases in 2026 are known and measurable expenses that will be incurred shortly after the end of the FPFTY. In fact, PECO's current collective bargaining agreements provide for annual 2.5% wage increases through 2026. There is no reason to disallow these known and measurable costs, which PECO is contractually obligated to incur.

In addition, PECO's annualization adjustment using the non-union salary increase that will become effective March 1, 2026, includes expenses that PECO will incur for some of the period until its next electric base rate case planned to be filed in two to three years. The use of a FPFTY and annualization adjustments that reflect known and measurable S&W increases is a reasonable approach to provide PECO with a fair opportunity to earn the rate of return used to set the rates in this proceeding during the period those rates are in effect.

18. Q. Do you agree with Ms. Wilson's and Mr. Defever's proposed adjustment that would eliminate recognition of the normalized cash payment to union employees made in connection with the ratification of the Company's current collective bargaining agreements?

A. No. The Company has consistently paid a ratification bonus to union employees each time it negotiates new union contracts, which is necessary to retain PECO's talented labor pool and ensure that the Company has access to skilled union workers to meet customer and system needs. Most recently, the Company paid the bonus in March 2021 upon ratification of PECO's current union contracts. Consistent with Commission practice,[2] PECO proposes to spread this expense over the length of the Company's collective bargaining agreements (i.e., six years). Thus, Ms. Wilson's and Mr. Defever's proposal to disallow costs related to the union contract ratification bonus that PECO incurs on a recurring basis should be rejected.

19. Q. Did I&E and the OCA make any adjustments related to PECO's payroll tax expense?

A. Yes. Ms. Wilson and Mr. Defever made concomitant adjustments to the Company's payroll tax expense based on their payroll expense recommendations. These should be rejected for the same reasons the adjustments related to the Company's payroll expenses should be rejected.

D. <u>Pension and Employee Benefits Expense</u>

20. Q. Please respond to the concomitant adjustments to pension and employee benefits expense proposed by Mr. Defever and Ms. Wilson related to their respective proposed vacancy rate adjustments.

[2] *See* James H. Cawley and Norman J. Kennard, *A Guide to Utility Ratemaking* (2018) at 86 (quoting *Pa. P.U.C. v. York Water Co.*, 78 P.U.R. 3d 113, 132 (1968) ("Expenses that occur irregularly during an extended period of years, but are certain of eventual recurrence, are a legitimate charge to ratepayers. Therefore, spreading of this expense over years of recurrence is logical.")).

A. The concomitant adjustments should be rejected for the reasons described in the rebuttal testimony of Company witness Marissa Humphrey in PECO Statement No. 2-R.

21. Q. Did Ms. Wilson make any further adjustments related to pension expense?

A. Yes. Ms. Wilson recommended a further reduction of approximately $1.89 million. The Company's FPFTY pension expense claim was based on a five-year average of contributions from 2021 through the FPFTY. Ms. Wilson stated it was unreasonable to use the 2021-2025 five-year average since, in her opinion, the Company's pension contributions in 2021 and 2022 were unusually high outliers and pension contributions are declining. Instead, Ms. Wilson proposed utilizing the Company's projected pension contribution for 2025.

22. Q. Why is it preferable to utilize a five-year average of the Company's pension contributions than simply relying upon the 2025 forecast?

A. The Company's pension contributions are subject to variability based on annual actuarial analyses prepared by Willis Towers Watson consistent with common practice and in accordance with ASC 715 Compensation – Retirement Benefits. Utilizing a five-year average is appropriate as the Company's actual contributions will be impacted by a number of factors, including macroeconomic factors that are beyond the Company's control.

23. Q. Please describe and respond to Ms. Wilson's proposed adjustment to PECO's FPFTY budgeted amount of employee benefits expense (net of pension expense) recorded to Federal Energy Regulatory Commission ("FERC") Account 926.

A. PECO's overall employee pension and benefits expense claim of $28,080,000 is shown on line 73 of Schedule D-4 of PECO Exhibit MJT-1 Revised. Ms. Wilson's recommended allowance of $23,501,000 is based on her incorrect belief that the entirety of the Company's supported employee benefits claim net of pension expense is $23,681,000. Ms. Wilson arrived at this amount by adding together the amounts on lines 19 and 23 of PECO Exhibit MJT-1, Schedule D-8, which annualizes non-pension employee benefits expense. However, Schedule D-8 only represents a subset of the employee benefits expense recorded to FERC Account 926. That schedule does not include $1,212,000 in other post-employment benefits ("OPEB") costs recorded in FERC Account 926 that are reflected in the Company's overall claim of $28,080,000 shown on MJT-1 Revised, Schedule D-4. The $1,212,000 in OPEB costs are based on studies performed by the Company's actuary, Willis Towers Watson, for the FPFTY. Ms. Wilson does not provide any basis to disallow the actuarial determined amount of OPEB expense for the FPFTY. Thus, Ms. Wilson improperly excluded $1,212,000 from the Company's FPFTY employee benefits claim.

E. <u>Rate Case Expense</u>

24. Q. Does the Company agree with I&E's or the OCA's proposed normalization periods?

A. No. PECO projects that it will need to file another rate case in two to three years, which formed the basis for the two-year normalization period the Company used in this case. Assuming a longer filing interval, as Ms. Wilson and Mr. Defever do, is at odds with Company witness Marissa Humphrey's testimony (PECO

Statement No. 2, p. 3) that PECO needs to invest approximately $3.5 billion in new and replacement electric utility plant between January 1, 2023 and December 31, 2025. With that level of investment and even marginal year-over-year increases in operating and maintenance expenses, it is not reasonable to assume that PECO could delay a subsequent base rate filing for at least three years.

F. Unamortized Balance of the Tax Accounting Repair Credit ("TARC") and Federal Tax Adjustment Clause ("FTAC") Being Refunded to Customers

25. Q. What adjustment has Ms. Wilson proposed to the Company's proposal to refund the final unamortized TARC and FTAC overcollection balances totaling $86,000 to customers over two years?

A. Ms. Wilson does not disagree with the amount of the unamortized balance of TARC and FTAC overcollections that will be credited to customers. Ms. Wilson proposes an adjustment to increase the period over which these overcollection balances are to be amortized for ratemaking purposes from two years, as the Company proposed, to three years. That change would reduce the annual amortization amount refunded to customers in this case by $14,333. The only reason Ms. Wilson offered for lengthening the amortization period is that doing so would be consistent with her recommendation to normalize rate case expense over three years.

26. Q. Please respond to Ms. Wilson's proposed adjustment.

A. For reasons I explained previously, a two-year normalization of rate case expense is reasonable and should be adopted. Accordingly, Ms. Wilson's proposed adjustment to require a three-year amortization of TARC and FTAC

overcollection balances to maintain consistent with her recommendation for rate case normalization is flawed and should be rejected.

G. Normalized Storm Expense

27. Q. How did PECO develop its claim for normalized storm expense?

A. PECO used a 60-month average reflecting the five annual periods ending March 31, 2024, adjusted for inflation, as a I explained in my direct testimony (PECO Statement No. 3, p. 45). As shown on PECO Exhibit MJT-1, Schedule D-13, the Company's original claim totaled $68.9 million.

The five-year period ending March 31, 2024, includes the costs PECO incurred for a major winter storm that occurred on January 9-14, 2024. This storm dropped heavy snow for the first time in two years across PECO's service area and brought high wind gusts. As a result, 194,662 PECO customers lost power from the storm, and 400 of the Company's employees were deployed to restore service. The storm repair and service restoration effort required PECO to replace 760 cross arms, 9,132 fuses, 171 utility poles, 128 transformers, and 62 miles of wire and cable. In PECO's initial filing, the $28.5 million of storm damage costs for the first quarter of 2024 used in the five-year average were a mixture of actual and estimated data. PECO now has the final actual costs for all storms in the first quarter of 2024, which is $25.0 million or approximately $3.5 million less than the amount reflected in PECO Exhibit MJT-1. Based on the availability of actual cost data, PECO has revised its claim for normalized storm expense (and the baseline for the Storm Reserve Account discussed later in my rebuttal testimony) from $68.9 million to $68.2 million, and the revised amount is set forth in PECO

Exhibit MJT-1 Revised, Schedule D-13, as I previously explained in Section II above.

28. Q. Please describe I&E's and the OCA's adjustments related to the Company's claim for normalized storm expense.

A. Ms. Wilson and Mr. Defever agree with PECO's use of a five-year average of its storm expense, but would remove the Company's adjustments for inflation. They both also recommend that PECO's 60-month average consist of the five calendar years ended December 31, 2023. Their calculation would remove data for the first quarter of 2024, which includes the costs of the January 2024 winter storm.

29. Q. What was their rationale for removing PECO's adjustments for inflation from the five-year average?

A. Mr. Defever stated that inflation factors should be removed from the Company's adjustment because these cost adjustments are not known and measurable, and they do not reflect the true cost of the expense. Ms. Wilson only stated that the Company's total storm expense significantly fluctuated year-to-year due to unpredictable weather conditions.

30. Q. Do you agree?

A. Absolutely not. The average unit cost of both labor and non-labor (such as material and equipment) has been increasing in the past five years and it will continue to increase during the FTY and FPFTY. It is a well-known fact that with the increased cost of labor and non-labor, the Company will have to spend more money in the future to restore the same amount of storm damage than in the past. The Consumer Price Index ("CPI") is a measure that examines the weighted

average of prices of a basket of consumer goods and services, such as transportation, food, and medical care. It is calculated by taking price changes for each item in the predetermined basket of goods and services, and averaging them. The CPI is one of the most frequently used statistics for identifying periods of inflation or deflation. The CPI is known and measurable. PECO believes it is a reasonable estimate of the inflation rates of the average storm restoration cost for the same level of effort by using the CPI. According to Mr. Defever, PECO's estimate does not reflect the true cost of the expense, but he did not provide any alternative that he believes better reflects the true cost of the expense.

31. Q. Should PECO's actual storm experience for the first quarter of 2024 be excluded from the calculation of normalized storm expense, as Ms. Wilson and Mr. Defever suggest?

A. No. Those events occurred during the FTY in this case, and the actual cost incurred for those events are known. Including that actual experience in the five-year average assures that all relevant data are included in the calculation of normalized storm costs.

H. <u>Infrastructure Investment and Jobs Act ("IIJA") Costs</u>

32. Q. Please address I&E Wilson's direct testimony regarding the costs PECO incurred to apply for IIJA funding in 2022 and 2023?

A. Ms. Wilson accepts PECO's adjustment to remove budgeted IIJA-related costs for 2024 and 2025 from its FPFTY claim but recommends disallowance of PECO's actual costs incurred in 2022 and 2023 in pursuing those federal grants. She asserts that PECO's adjustment does not meet the Commission's criteria for

deferred accounting treatment because the costs of pursuing grant funding are expected and ongoing for all utilities. Ms. Wilson's position is inconsistent with the Commission's Opinion and Order entered July 13, 2023, at Docket No. P-2022-3032929, affording regulatory asset authorization to all utilities for costs associated with seeking federal funding made available by the IIJA. Contrary to Ms. Wilson's contention, costs to apply for IIJA funding were not anticipated in 2022 and 2023. The IIJA was signed into law by President Biden on November 15, 2021, well after the record closed in PECO's electric base rate proceeding at Docket No. P-2021-3024601, which established the Company's rates in effect in 2022 and 2023. The U.S. Department of Energy ("DOE") subsequently announced its Grid Resilience and Innovation Partnership ("GRIP") Program IIJA funding opportunity on October 18, 2023, and PECO was selected to negotiate an award of up to $100 million under this program. The $411,000 included in PECO's FPFTY claim is a direct result of the Company's pursuit of IIJA funding and fits within the Commission's parameters set forth in its IIJA Order for tracking incremental, extraordinary, and non-recurring IIJA-related expenses and creating a regulatory asset.

33. Q. Are the costs of pursuing IIJA funding insubstantial as Ms. Wilson suggests?

A. No. PECO has already incurred $411,000 prior to the end of 2023, related to its request for IIJA-funding and budgeted for another $653,000 per year in 2024 and 2025 for its efforts to secure $100 million under DOE's GRIP. In short, PECO expects to incur substantial incremental IIJA-related costs totaling well over $1 million. I also note that even the $411,000 of IIJA costs incurred in 2022 and

2023 is comparable with the magnitude of several of Ms. Wilson's proposed adjustments, including rate case expense, payroll taxes, severance, employee activity costs, and TARC and FTAC amortization expense.

I. Gains on Disposition of Utility Property

34. Q. Mr. Defever contends that a five-year average (2019-2023) of PECO's gains on sale of utility property should be used to reduce the Company's revenue requirement in this case. Do you agree?

A. No. All gains were on sales of land and were recorded in FERC Account No. 421.1, which is a non-utility account. Contrary to Mr. Defever's assumption that customers are funding the return of and on utility land in service,[3] customers are only paying carrying charges on such property, and PECO is not recovering the value of the land itself from customers, similar to a landlord-tenant arrangement. In addition, PECO purchases land for infrastructure projects well ahead of the start of construction. However, the Company does not receive rate base recognition of such land held for future use and is not able to accrue Allowance for Funds Used During Construction either, until construction is complete and the distribution infrastructure is placed in service. For all of these reasons, gain on utility property sales are properly recorded below-the-line for ratemaking purposes.

[3] See OCA's response to Interrogatory PECO-OCA-II-3 attached hereto as PECO Exhibit MJT-4.

J. Cash Working Capital

35. Q. Please describe the adjustments to PECO's CWC claim proposed by I&E and the OCA.

A. Ms. Wilson and Mr. Defever proposed concomitant adjustments to the Company's CWC based on proposed expense adjustments. PECO agrees that its CWC allowance should be revaluated if the Company is not awarded its full claim.

IV. STORM RESERVE ACCOUNT

36. Q. Did any parties disagree with PECO's request to establish a tracker and deferral account for storm damage expense?

A. Yes. Witnesses on behalf of I&E and the OCA submitted testimony opposing the Company's proposal based on two primary concerns. First, according to I&E witness Wilson and OCA witness Defever, deferred accounting treatment is not necessary because, in their view, the use of a five-year historic average of actual costs to establish the going level of storm damage expense in the Company's base rates will normalize the expense over time and addresses PECO's concern about over- and under-recovery without the need for a reserve account. Second, Ms. Wilson asserts that a deferral mechanism such as PECO's proposed Storm Reserve Account could reduce or eliminate the Company's incentive to control its storm damage costs.

37. Q. Do you agree with I&E's and the OCA's opinion that there is no compelling need to establish a Storm Reserve Account in this case?

A. No. The purpose of the Company's request for deferral accounting authorization is to protect both customers and PECO from the variations between forecasted storm damage expense based on a five-year average of historical actuals and actual storm damage expense in a specific year that occur due to the unpredictability of storm events. The Commission has already determined that a mechanism like the Storm Reserve Account is necessary for EDCs based on the findings supporting its approval of a Storm Damage Expense Rider for PPL Electric Utilities, Corp., namely, that storm damage expenses: (1) are not within the control of a utility; (2) are variable and difficult to project for purposes of prospective recovery; and (3) have become even more significant as a result of "the size of recent storm events and our increasing emphasis on enhanced system reliability."[4] Considering the Commission's findings, the issue of whether an alternative to traditional ratemaking for storm damage expense is necessary should not be in dispute.

As explained in my direct testimony, PECO's storm damage expense can materially increase or decrease due to volatility in the frequency, severity and duration of weather events that are outside the Company's control. Deferred accounting authorization via the Storm Reserve Account is a fair way to ensure that customers and the Company do not bear more than PECO's actual costs incurred to remediate storm damage. Significantly, as discussed in my direct testimony (pp. 74-75), from 2016 through 2023, customers would have realized a

[4] *See Pa. P.U.C. v. PPL Elec. Utils. Corp.*, Docket No. R-2012-2290597 (Opinion and Order entered Dec. 28, 2012), pp. 21-23; see also *Pa. P.U.C. v. PPL Elec. Utils. Corp.*, Docket No. R-2012-2290597 (Opinion and Order entered Apr. 23, 2014), pp. 15, 21-22.

net benefit of approximately $15 million through a deferral mechanism for storm damage expense. In fact, over the eight years reflected in that analysis, customers would have realized net benefits (actual costs lower than the rate allowance) in five years, including each year PECO's current rates have been in effect (2022 and 2023).

Mr. Defever criticizes the comparative analysis of PECO's authorized and actual levels of storm damage expense presented in Table 1 of my direct testimony. While Mr. Defever is correct that PECO's last three electric base rate cases were resolved by black box settlement, PECO used its claimed amounts based on a five-year average as a representative figure for storm damage expense embedded in rates to provide a comparison to actual costs. Notably, using the OCA's and I&E's recommended rate allowance in PECO's last electric base rate case ($48 million versus PECO's claim of $51 million), customers would have realized net benefits of $33 million.

38. Q. Will deferred accounting authorization remove incentives for PECO to control its storm damage costs?

A. No. All deferred net benefits or net liabilities will be claimed in PECO's next rate case, which will provide all interested parties the same opportunity for a detailed ratemaking review, as they have today, to ensure that storm damage expenses were reasonable and prudently incurred. Furthermore, the Company is strongly committed to actively managing its expense and investing in storm hardening and resiliency measures to reduce the impact of future weather events on customer rates. As Ms. Wilson acknowledges, those investments may reduce storm

remediation costs in the future.[5] The Company's proposed Storm Reserve Account would protect against a substantial over-recovery by the Company and corresponding overpayment by customers arising from reduced future outages associated with PECO's storm hardening and resiliency initiatives.

39. Q. Please comment on Mr. Defever's and Ms. Wilson's proposed modifications to PECO's proposed Storm Reserve Account if the Commission approves such a mechanism.

A. Mr. Defever contends that the expenses incurred for "extraordinary storms," which he defines as storm damage costs exceeding 5% of income,[6] should not be recorded to the reserve account, and the PUC should require the Company to petition for deferral of those costs separately. This recommendation is internally inconsistent with Mr. Defever's proposal to use a five-year average of *actual* costs to calculate normalized storm expense. As I explained in my direct testimony, PECO's five-year average reflects the Company's experience for that historical period, including major and extraordinary storms.

I&E witness Wilson also recommends a one-sided application of interest only when refunding a regulatory liability to customers in subsequent rate cases. Applying interest symmetrically to both over- and under-collections, as PECO proposes, is equitable to both customers and the Company because it provides for identical treatment.

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[5] *See* I&E's response to Interrogatory PECO-I&E-II-4 attached hereto as PECO Exhibit MJT-5.

[6] *See* OCA's response to Interrogatory PECO-OCA-II-5 attached hereto as PECO Exhibit MJT-6.

40. Q. Does PECO object to I&E's and the OCA's proposal to determine the appropriate amortization period for the Storm Reserve Account in the subsequent rate case when deferred amounts are claimed?

A. No. PECO will propose a reasonable amortization period in its next base rate case where it seeks rate recovery of the net credit or debit balances in the Storm Reserve Account.

V. OFFSET FACTORS IN THE UNIVERSAL SERVICE FUND CHARGE

41. Q. Have any parties opposed PECO's proposal to change the offset factor applied to reconcilable CAP costs recovered through the USFC from 27% to 10.5%?

A. Yes. Mr. Colton claims that PECO did not justify leaving the working capital component of the USFC factor at 5% while updating the uncollectible expense component established in 2008 by the DSP Settlement. According to Mr. Colton, the increase in the level of arrears leading to bad debt write-offs since the DSP Settlement would support a working capital offset of 20.85%.

Mr. Colton also contends that PECO's proposal to lower the bad debt component of the USFC offset factor from 22% to 5.5% based on the difference between the three-year average (2021-2023) uncollectible rate for CAP customers and all residential customers artificially reduces the offset factor because of the impact of the COVID-19 pandemic on collections in 2021. Ms. Golden addresses Mr. Colton's objections to PECO's proposed update to the bad debt offset percentage in PECO Statement No. 10-R.

42. Q. Do you agree with Mr. Colton that the working capital component of the USFC offset factor should be updated if the Commission approves PECO's proposed changes to the bad debt offset percentage?

A. In part. I agree that PECO should update both components of the USFC offset factor with current data. However, I disagree with Mr. Colton's assertion that the 5% should be increased by more than 400% to 20.85%. Mr. Colton's position is based on his allegation that the level of residential arrears has quadrupled since the DSP Settlement in 2008. While it is true that the dollar amount of PECO's residential arrears have increased by 49% since 2008, the level of those arrears is impacted by many variables in addition to participation in CAP, such as write-offs, revenues, the economy, weather, and demographics.

Contrary to Mr. Colton's assertion, the calculations underlying the working capital adjustment in the DSP Settlement were not based on three-year average residential customer arrears. The basis for those calculations was the methodology recommended by the OCA in PECO's 2008 gas rate case using the age of residential arrears at charge-offs based on data at that time ("2008 OCA Methodology"). As shown on PECO Exhibit MJT-7, employing PECO's current data on incremental age of arrears at charge-off in the 2008 OCA methodology results in a CWC offset percentage of 5.0%. Accordingly, it is appropriate to maintain the current offset percentage for working capital as PECO initially proposed.

VI. CONCLUSION

43. Q. Does this complete your rebuttal testimony at this time?

A. Yes. It does.

PECO Energy Company, R-2024-3046931 (Electric)

PECO Interrogatories to the Office of Consumer Advocate
Set II

PECO-OCA-II-3. Refer to OCA Statement No. 1, page 29, lines 8-17. Please provide a citation to all Commission precedent or other Pennsylvania authority supporting your statement that "ratepayers are entitled to receive the benefit of gains on sales of utility property."

Response:

I am not aware of Commission precedent or other Pennsylvania authority supporting my statement. My position that ratepayers are entitled to receive the benefit of gains on sales of utility property is based on ratepayers funding the return of and on utility property. In addition, because the gains on sale of utility property are recurring, a 5-year average of these gains should be reflected in rates.

Dated: July 1, 2024

Sponsored by: John Defever

Pennsylvania Public Utility Commission v.
PECO Energy Company – Electric Division
Docket No. R-2024-3046931

Responses of the Bureau of Investigation and Enforcement to the Interrogatories of PECO Energy Company – Electric Division – Set II
Witness: Christine Wilson

PECO-I&E-II-4 Refer to I&E Statement No. 1, page 38, lines 14-17. Please explain in detail why there is a conflict between the Company's significant effort to focus on storm hardening and resiliency and PECO's proposed storm reserve account.

Response **As stated in Ms. Wilson's direct testimony on I&E Statement No. 1, p. 38, all of the money spent on storm hardening and resiliency may reduce potential future storm remediation costs in the future. If such repairs would not reduce future outages and the damage that causes such outages, it is questionable whether such funds are well spent.**

PECO Energy Company, R-2024-3046931 (Electric)

PECO Interrogatories to the Office of Consumer Advocate
Set II

PECO-OCA-II-5. Please define the term "extraordinary storm" as used in as used by Mr. Defever on pages 40-41 of OCA Statement No. 1.

Response:

The use of the term "extraordinary storm" is consistent with the use on page 72 of Mr. Trzaska's Direct Testimony where he said: "The Commission regularly authorizes utilities to defer costs for accounting purposes arising from extraordinary and non-recurring events to provide the utility an opportunity to claim those costs for recovery in a future rate proceeding." I also note that the Commission has discussed extraordinary expense with reference to the threshold of 5% provided in General Instruction 7 of the Uniform System of Accounts. See Petition of West Penn Power Company for Authority to Defer for Regulatory Accounting and Reporting Purposes Certain Losses from Extraordinary Storm Damage, Docket No. P-2010-2216111, (April 1, 2011), Order at 4-5; https://www.puc.pa.gov/pcdocs/1126417.docx; see also Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, 18 CFR part 101. https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101.

Dated: July 1, 2024

Sponsored by: John Defever

Calculation of Working Capital Offset Factor

	Arrears	$ 1,000	
1	Incremental Age (Billing Date to Due Date)	22	
2	Age of Arrears at Charge-offs	189	
3	Days Remaining Until Charge-off (Age of Arrears Minus Incremental Age)	167	
4	Dollar Lag Days (Days Remaining X Dollars of Arrears)	$ 167,000	
5	Annualized Weighted Return	7.98%	PECO Exhibit MJT-1, Schedule B-7, Line 6, Column 4
6	Gross Up Factor for Taxes	37.57%	PECO Exhibit MJT-1, Schedule D-19, Line 50
7	Weighted Return (Annualized Return X Gross Up for Taxes)	11.0%	
8	Days Per Year	365	
9	Daily Return (Weighted Return / Days Per Year)	0.030%	
10	Annualizing Factor	1	
11	Annualized Working Capital per $1,000 Receivables	$ 50.23	
12	Working Capital Per $1 Receivables	$ 0.0502	
13	PECO CAP Rate Working Capital Offset	5.0%	

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046931**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Michael J. Trzaska, hereby state that I am a Principal Regulatory and Rate Specialist for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 3
- PECO Exhibit MJT-1
- PECO Exhibit MJT-2
- PECO Exhibit MJT-3

- PECO Statement No. 3-R
- PECO Exhibit MJT-1 Revised
- PECO Exhibit MJT-4
- PECO Exhibit MJT-5
- PECO Exhibit MJT-6
- PECO Exhibit MJT-7

Dated: August 5, 2024

Michael J. Trzaska

PECO Statement No. 4:

Direct Testimony of Caroline Fulginiti

PECO ENERGY COMPANY
STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

DIRECT TESTIMONY

WITNESS: CAROLINE FULGINITI

SUBJECTS: OVERVIEW OF PECO ENERGY COMPANY'S ACCOUNTING PROCESSES; ALLOCATION OF COSTS BETWEEN ELECTRIC AND GAS OPERATIONS; AND ELECTRIC DIVISION DEPRECIATION CLAIMS

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
CAROLINE FULGINITI

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Caroline Fulginiti. 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 Exelon as Vice President and Assistant Controller. In that capacity, I am responsible for maintaining PECO Energy Company's ("PECO's" or the "Company's") accounting books and records under United States Generally Accepted Accounting Principles ("GAAP") and the Federal Energy Regulatory Commission's ("FERC") *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act* ("Uniform System of Accounts"). In addition, I am responsible for PECO's financial reporting to the U.S. Securities and Exchange Commission ("SEC"), the FERC, and the Pennsylvania Public Utility Commission ("PUC" or "Commission").

3. Q. Please describe your educational background.

A. I received a Bachelor of Business Administration from James Madison University and a Master of Professional Accountancy from Indiana University.

4. Q. Please describe your professional experience.

A. Upon graduation, I was hired as an audit associate for PricewaterhouseCoopers,

LLP in Chicago. After seven years at PricewaterhouseCoopers, I began employment with Exelon Corporation in 2007. I held various roles at Exelon, including Manager of Accounting Policy & Research, Manager of Power Team Accounting, and Manager of PECO Accounting prior to being promoted to Director of Property Accounting and Project Controls in 2014. In 2016, I became Director of Financial Operations for PECO, overseeing the Company's capital and operations and maintenance budgeting process. In January 2020, I became Director of Accounting at PECO. I assumed my current responsibilities as Vice President and Assistant Controller for Exelon in February 2024.

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

A. I will provide a general overview of PECO's accounting processes. I will then describe how PECO allocates common costs between its electric and natural gas operations. Finally, I will present and explain PECO's claims for accrued and annual depreciation related to the utility plant in service of PECO's Electric Division as of the end of the historic test year (December 31, 2023) ("HTY"), future test year (December 31, 2024) ("FTY"), and the fully projected future test year (December 31, 2025) ("FPFTY").

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

A. I am sponsoring PECO Exhibits CF-1, CF-2, and CF-3, which include, respectively, the results of the depreciation studies related to the original cost of PECO's electric and common plant in service at December 31, 2023, and estimated to be in service at December 31, 2024 and December 31, 2025. I am also sponsoring PECO Exhibit CF-4, which is a service-life study performed by

Gannett Fleming, Inc. ("Gannet Fleming") based upon plant balances at December 31, 2018.

II. OVERVIEW OF PECO'S ACCOUNTING PROCESSES

7. Q. How are PECO's accounting records maintained?

A. The Company's accounting records are kept in accordance with GAAP and FERC's Uniform System of Accounts, as required by the PUC's regulations at 52 Pa. Code § 57.42(a). In addition, PECO maintains a continuing property records system in accordance with PUC and FERC requirements.

8. Q. Do PECO's continuing property records accurately reflect the original cost of the property in question?

A. Yes, they do. A determination of the original cost of PECO's electric plant was made in the 1940s with the approval of the PUC. Subsequent plant additions, retirements, and adjustments have been recorded on an original cost basis in accordance with GAAP, the PUC's regulations, and the Uniform System of Accounts.

10. Q. Are PECO's books and records audited?

A. Yes, PECO's books and records are audited. Exelon Corporation maintains Exelon Audit Services ("EAS"), which routinely audits various aspects of PECO's operations. In addition, PECO's books and records are audited annually by its outside auditors.

In 2022, the PUC completed a Management and Operations Audit of PECO that

included a review of the Company's internal audit process.[1] The PUC's review of the internal audit process resulted in no recommendations.

11. Q. How can you be sure that all property reflected in PECO's plant accounts is, in fact, used and useful?

A. As explained in the testimony of Company witness Nicole L. LeVine in PECO Statement No. 1, the assets included in PECO's rate base in this case are, or by the end of the FTY and the FPFTY will be, in service and used by PECO to provide electric service to its customers. Moreover, PECO has a process in place requiring that: (1) a record be made in the field at the time any property unit is added to service or permanently removed from service; and (2) based on the records made in the field, appropriate accounting entries be made to the Company's property accounts to add or remove, respectively, the original cost of any property unit that was added or retired. Individuals with appropriate authority must review and approve the entries that are made to record the addition and removal of property units from the Company's plant accounts. Additionally, EAS performed an audit of the controls surrounding PECO's fixed asset process in 2015, which included review of fixed asset accounting records. EAS concluded that the processes and general control environment – which includes those activities necessary to provide reasonable assurance that risks are being managed and objectives met – are effective.

[1] *See* Management and Operations Audit of PECO Energy Company, Docket No. D-2021-3023906 (Issued July 2022).

III. ALLOCATION OF COSTS BETWEEN ELECTRIC AND GAS OPERATIONS

12. Q. Does PECO maintain separate books and records for its electric and natural gas operations?

A. Yes. Under applicable PUC and FERC regulations, PECO is required to maintain, separately, certain income statement accounts and to maintain, separately, certain balance sheet accounts for its electric and natural gas operations.

13. Q. How does the Company allocate "common plant" assets between its two divisions?

A. "Common plant" assets (i.e., facilities, such as PECO's headquarters office building in Philadelphia, that are used to provide both electric and gas service) are allocated on the basis of a three-part formula, with equal weight given to relative plant investment, total revenue, and number of customers. The allocation factors utilized for purposes of this rate filing are set forth in the applicable schedules of PECO Exhibits MJT-1, MJT-2, and MJT-3.

14. Q. Are operating expenses handled in the same fashion?

A. No, a different method is used to allocate operating expenses. The Company develops factors to allocate between electric and gas operations those operating expenses that are not directly assigned. PECO reviews these factors annually and updates them as necessary to reflect the forces driving the costs to which they apply.

15. Q. Please explain the method used to allocate non-assignable Administrative and General ("A&G") expense.

A. Expenses in this category consist of the labor and other resources of the Company's A&G departments, such as Finance, Marketing, and Accounting, that provide service to both the electric and gas divisions. Non-assignable expenses in these areas are allocated to electric operations based upon a percentage calculated by dividing: (1) the previous year's Operating & Maintenance ("O&M") expenses that were directly assigned to electric operations, by (2) the total of all the previous year's O&M expenses that were directly assigned to electric and gas operations.

16. Q. Please explain the method used to allocate non-assignable bad debt expense.

A. Bad debt expense associated with customer accounts receivable is allocated to electric operations based on the historical ratio of accounts receivable charged off. Although bad debt expense is allocated for accounting purposes, uncollectible accounts expense included in PECO's revenue requirement for ratemaking purposes is calculated based on the net uncollectible accounts charged off, expressed as a percentage of total tariff revenue, as explained by Company witness Michael J. Trzaska in PECO Statement No. 3.

IV. PECO ELECTRIC DIVISION DEPRECIATION CLAIMS

17. Q. Has a service-life study of PECO's electric utility plant in service been performed?

A. Yes. With the assistance of Gannett Fleming, a service-life study was performed based on PECO's plant balances at December 31, 2018, which is provided as

PECO Exhibit CF-4. The study was filed with the PUC in April 2020 at Docket No. M-2020-3020569. Prior to the Company's 2018 service-life study, a service-life study was performed in 2014 based on PECO's plant balances at December 31, 2013.

18. Q. Have you prepared exhibits presenting the results of PECO's depreciation studies?

A. Yes. PECO Exhibits CF-1, CF-2, and CF-3 reflect PECO's electric and common plant in service as of December 31, 2023, 2024, and 2025 respectively. Exhibits CF-1, CF-2, and CF-3 rely upon the service lives and depreciation rates developed in the Company's 2018 service-life study.

19. Q. What is the purpose of the depreciation study?

A. PECO is relying principally on data for a FPFTY ending December 31, 2025 to support its proposed increase in revenue requirement in this case. Accordingly, the purpose of the depreciation study is to provide the basis to calculate the estimated 2025 annual depreciation accruals related to plant in service for ratemaking purposes and, using procedures approved by the PUC, to estimate PECO's book reserve at December 31, 2025.

PECO uses the remaining-life method of depreciation, which calculates depreciation accruals designed to recover the original cost less accrued depreciation of utility plant over the estimated remaining life of that plant, by depreciable group.

20. Q. Please describe PECO Exhibits CF-1, CF-2, and CF-3.

A. PECO Exhibit CF-1 is titled "Annual Depreciation Accruals Related to Utility Plant in Service for 2023." This exhibit includes the results of the depreciation study related to the original cost of PECO's plant in service at December 31, 2023. The exhibit also includes the detailed depreciation calculations used to determine 2024 depreciation rates, which are used in calculating the estimated 2024 Annual Depreciation Accruals shown in PECO Exhibit CF-2.

PECO Exhibit CF-2 is titled "Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2024." This exhibit includes the results of the depreciation study related to the estimated original cost of PECO's plant in service at December 31, 2024. PECO Exhibit CF-2 includes PECO's FTY plant additions for electric and allocated common plant assets claimed in rate base in this case and reflects the depreciation accruals related to those additions in the column titled "2024 Estimated Annual Depreciation Accrual."

PECO Exhibit CF-3 is titled "Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2025." This exhibit includes the results of the depreciation study related to the estimated original cost of PECO's plant in service at December 31, 2025. PECO Exhibit CF-3 includes PECO's FPFTY plant additions for electric and allocated common plant assets claimed in rate base in this case and reflects the depreciation accruals related to those additions in the column titled "2025 Estimated Annual Depreciation Accrual."

21. Q. Has the Commission previously approved PECO's use of the remaining-life method of depreciation?

A. Yes. In 1984, the Commission approved PECO's use of the remaining-life method in PECO's rate proceeding at Docket No. R-842590, and also approved PECO's adjusted book reserve as the measure of accrued depreciation for ratemaking. PECO has employed the remaining-life method in each of the Annual Depreciation Reports filed with the Commission since it adopted the remaining-life method.

22. Q. How was the accumulated depreciation recorded in the Company's book reserve ("accumulated depreciation") used in the calculation of annual depreciation?

A. The accumulated depreciation, by account, at December 31, 2023, is one of the factors used in calculating the annual depreciation accruals. The methodology used to calculate the annual depreciation accrual is consistent with the methodology described in the 2018 Depreciation Study (PECO Exhibit CF-4).

23. Q. How was the estimated accumulated depreciation at December 31, 2024 determined?

A. As shown in PECO Exhibit CF-2, the December 31, 2024 estimated accumulated depreciation was developed by: (1) adding the 2024 estimated annual depreciation accruals to the actual accumulated depreciation by account as of January 1, 2024; (2) subtracting the estimated 2024 plant retirements by account; and (3) adding 2024 estimated salvage and subtracting estimated removal costs that are closed to the book reserve, by account. The 2024 annual depreciation accruals are

estimated by adding the following three items: (1) the estimated net book value of depreciable plant by account as of December 31, 2023, multiplied by the depreciation rates shown in PECO Exhibit CF-2; (2) the 2024 estimated plant additions multiplied by the depreciation rate (using a half-year convention) for the appropriate accounts; and (3) the 2024 estimated salvage or cost of removal multiplied by the depreciation rate (using a half-year convention) for the appropriate account.

24. Q. How was the estimated accumulated depreciation at December 31, 2025 determined?

A. As shown in PECO Exhibit CF-3, the December 31, 2025 estimated accumulated depreciation was developed by: (1) adding the 2025 estimated annual depreciation accruals to the estimated accumulated depreciation by account as of January 1, 2025; (2) subtracting the 2025 estimated plant retirements by account; and (3) adding 2025 estimated salvage and subtracting estimated removal costs that are closed to the book reserve, by account. The 2025 annual depreciation accruals are estimated by adding the following three items: (1) the estimated net book value balance of depreciable plant by account as of December 31, 2024, multiplied by the depreciation rates shown in PECO Exhibit CF-3; (2) the 2025 estimated plant additions multiplied by the depreciation rate (using a half-year convention) for the appropriate account; and (3) the 2025 estimated salvage or cost of removal multiplied by the depreciation rate (using a half-year convention) for the appropriate account.

25. Q. Have you prepared schedules that summarize the development of the original cost of gross plant, estimated accumulated depreciation, estimated net book value of depreciable plant, and estimated annual depreciation accruals, by property account, for utility plant in service at December 31, 2025?

A. Yes. PECO Exhibit CF-3 provides this information. The original cost of gross plant in service at December 31, 2025 was calculated by adding the estimated plant additions by account for 2025 to, and subtracting the estimated plant retirements for 2025 from, the estimated original cost of gross plant as of December 31, 2024. The estimated net book value of depreciable plant at December 31, 2025 was calculated by subtracting the estimated accumulated depreciation at December 31, 2025 from the estimated original cost of gross plant at December 31, 2025. The 2025 annual depreciation accruals were estimated by adding the following three items: (1) the estimated net book value balance of depreciable plant by account as of December 31, 2024, multiplied by the depreciation rates shown in PECO Exhibit CF-3; (2) the 2025 estimated plant additions multiplied by the depreciation rate (using a half-year convention) for the appropriate accounts; and (3) the 2025 estimated salvage or cost of removal multiplied by the depreciation rate (using a half- year convention) for the appropriate accounts.

V. CONCLUSION

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

A. Yes, it does.

PECO Exhibit CF-1:

Annual Depreciation Accruals Related to Utility Plant in Service for 2023

Annual Depreciation Accruals Related to
Utility Plant in Service for 2023

Summary –

This exhibit is based on the results of the 2018 Depreciation Study and updated to reflect the original cost of PECO's electric and common plant in service at December 31, 2023. The report also includes the detailed depreciation calculations used to determine 2024 depreciation rates, which are used in calculating the estimated 2024 Annual Depreciation Accruals shown in PECO Exhibit CF-2.

Note:
The system generated reports show the date for each utility account as of January 1, 2024. The balances as of December 31, 2023 are the same as the balances as of January 1, 2024.

Generation Arrangement Report

PECO Elect 361 Composite 2024

Account: PECO Elect 361 Composite
Dispersion: 50.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$25,513,121.36	50.00	49.53	0.9905	1.0000	$25,271,959.89	$510,262.43
2022	1.50	$9,060,906.17	50.00	48.59	0.9717	1.0000	$8,804,542.35	$181,218.12
2021	2.50	$9,566,372.39	50.00	47.65	0.9529	1.0000	$9,116,098.98	$191,327.45
2020	3.50	$8,777,171.21	50.00	46.71	0.9342	1.0000	$8,199,972.28	$175,543.42
2019	4.50	$13,482,179.75	50.00	45.78	0.9156	1.0000	$12,344,731.03	$269,643.60
2018	5.50	$23,782,554.95	50.00	44.86	0.8971	1.0000	$21,335,600.83	$475,651.10
2017	6.50	$17,953,908.46	50.00	43.93	0.8787	1.0000	$15,775,871.26	$359,078.17
2016	7.50	$3,142,009.77	50.00	43.02	0.8604	1.0000	$2,703,275.96	$62,840.20
2015	8.50	$12,256,809.89	50.00	42.11	0.8421	1.0000	$10,321,955.64	$245,136.20
2014	9.50	$6,130,443.33	50.00	41.20	0.8240	1.0000	$5,051,640.30	$122,608.87
2013	10.50	$1,487,739.88	50.00	40.30	0.8060	1.0000	$1,199,152.23	$29,754.80
2012	11.50	$2,086,871.88	50.00	39.41	0.7881	1.0000	$1,644,738.21	$41,737.44
2011	12.50	$10,718,599.87	50.00	38.52	0.7704	1.0000	$8,257,248.99	$214,372.00
2010	13.50	$3,437,820.86	50.00	37.64	0.7527	1.0000	$2,587,759.56	$68,756.42
2009	14.50	$1,865,848.50	50.00	36.76	0.7352	1.0000	$1,371,823.29	$37,316.97
2008	15.50	$2,439,794.97	50.00	35.89	0.7179	1.0000	$1,751,431.69	$48,795.90
2007	16.50	$12,973,377.95	50.00	35.03	0.7006	1.0000	$9,089,549.51	$259,467.56
2006	17.50	$1,396,335.35	50.00	34.18	0.6836	1.0000	$954,471.23	$27,926.71
2005	18.50	$737,477.20	50.00	33.33	0.6666	1.0000	$491,619.46	$14,749.54
2004	19.50	$1,765,497.39	50.00	32.49	0.6498	1.0000	$1,147,297.67	$35,309.95
2003	20.50	$708,565.51	50.00	31.66	0.6332	1.0000	$448,684.21	$14,171.31
2002	21.50	$1,247,479.02	50.00	30.84	0.6168	1.0000	$769,424.76	$24,949.58
2000	23.50	$130,331.23	50.00	29.22	0.5844	1.0000	$76,164.01	$2,606.62
1999	24.50	$116,951.93	50.00	28.42	0.5685	1.0000	$66,481.63	$2,339.04
1998	25.50	$618,998.50	50.00	27.63	0.5527	1.0000	$342,118.66	$12,379.97
1997	26.50	$107,059.39	50.00	26.86	0.5371	1.0000	$57,504.89	$2,141.19
1996	27.50	$1,772,920.80	50.00	26.09	0.5217	1.0000	$925,011.74	$35,458.42
1995	28.50	$309,864.32	50.00	25.33	0.5066	1.0000	$156,964.51	$6,197.29
1994	29.50	$371,029.81	50.00	24.58	0.4916	1.0000	$182,385.09	$7,420.60
1993	30.50	$648,306.26	50.00	23.84	0.4768	1.0000	$309,096.32	$12,966.13
1992	31.50	$934,610.88	50.00	23.11	0.4622	1.0000	$431,970.52	$18,692.22
1991	32.50	$1,489,227.52	50.00	22.39	0.4478	1.0000	$666,913.75	$29,784.55

Generation Arrangement Report

PECO Elect 361 Composite 2024

Account: PECO Elect 361 Composite
Dispersion: 50.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1990	33.50	$811,818.36	50.00	21.68	0.4337	1.0000	$352,064.93	$16,236.37
1989	34.50	$2,119,818.65	50.00	20.99	0.4197	1.0000	$889,789.89	$42,396.37
1988	35.50	$3,441,572.85	50.00	20.30	0.4061	1.0000	$1,397,481.56	$68,831.46
1987	36.50	$586,462.95	50.00	19.63	0.3926	1.0000	$230,248.37	$11,729.26
1986	37.50	$106,326.03	50.00	18.97	0.3794	1.0000	$40,340.11	$2,126.52
1985	38.50	$248,699.67	50.00	18.32	0.3665	1.0000	$91,136.83	$4,973.99
1984	39.50	$88,712.98	50.00	17.69	0.3538	1.0000	$31,384.02	$1,774.26
1983	40.50	$17,372.39	50.00	17.07	0.3414	1.0000	$5,930.29	$347.45
1982	41.50	$37,581.28	50.00	16.46	0.3292	1.0000	$12,373.39	$751.63
1981	42.50	$514,366.18	50.00	15.87	0.3174	1.0000	$163,269.67	$10,287.32
1980	43.50	$86,302.36	50.00	15.29	0.3059	1.0000	$26,399.71	$1,726.05
1979	44.50	$1,246,696.89	50.00	14.73	0.2947	1.0000	$367,390.63	$24,933.94
1978	45.50	$50,331.55	50.00	14.19	0.2838	1.0000	$14,284.35	$1,006.63
1977	46.50	$9,349.05	50.00	13.66	0.2733	1.0000	$2,554.66	$186.98
1976	47.50	$23,748.67	50.00	13.15	0.2630	1.0000	$6,246.80	$474.97
1975	48.50	$1,513,247.43	50.00	12.66	0.2532	1.0000	$383,105.80	$30,264.95
1974	49.50	$457,378.00	50.00	12.18	0.2436	1.0000	$111,436.26	$9,147.56
1973	50.50	$485,110.16	50.00	11.72	0.2345	1.0000	$113,741.58	$9,702.20
1972	51.50	$1,317,663.27	50.00	11.28	0.2256	1.0000	$297,322.56	$26,353.27
1971	52.50	$2,430,148.90	50.00	10.86	0.2172	1.0000	$527,749.68	$48,602.98
1970	53.50	$1,124,597.76	50.00	10.45	0.2090	1.0000	$235,082.39	$22,491.96
1969	54.50	$1,085,931.69	50.00	10.06	0.2012	1.0000	$218,540.16	$21,718.63
1968	55.50	$276,453.66	50.00	9.69	0.1938	1.0000	$53,572.83	$5,529.07
1967	56.50	$605,071.51	50.00	9.33	0.1866	1.0000	$112,933.47	$12,101.43
1966	57.50	$1,302,208.56	50.00	8.99	0.1798	1.0000	$234,148.73	$26,044.17
1965	58.50	$277,164.06	50.00	8.66	0.1733	1.0000	$48,023.47	$5,543.28
1964	59.50	$397,272.38	50.00	8.35	0.1670	1.0000	$66,342.37	$7,945.45
1963	60.50	$1,098,755.39	50.00	8.05	0.1610	1.0000	$176,872.37	$21,975.11
1962	61.50	$218,138.04	50.00	7.76	0.1552	1.0000	$33,851.83	$4,362.76
1961	62.50	$657,639.55	50.00	7.48	0.1496	1.0000	$98,384.76	$13,152.79
1960	63.50	$458,197.04	50.00	7.21	0.1442	1.0000	$66,078.31	$9,163.94
1959	64.50	$242,078.17	50.00	6.95	0.1390	1.0000	$33,643.03	$4,841.56

Generation Arrangement Report

PECO Elect 361 Composite 2024

Account: PECO Elect 361 Composite
Dispersion: 50.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1958	65.50	$537,528.45	50.00	6.69	0.1339	1.0000	$71,969.39	$10,750.57
1957	66.50	$511,494.71	50.00	6.45	0.1289	1.0000	$65,941.75	$10,229.89
1956	67.50	$842,021.24	50.00	6.20	0.1241	1.0000	$104,458.21	$16,840.42
1955	68.50	$489,194.61	50.00	5.96	0.1193	1.0000	$58,349.53	$9,783.89
1954	69.50	$514,727.78	50.00	5.73	0.1146	1.0000	$58,980.16	$10,294.56
1953	70.50	$267,109.53	50.00	5.50	0.1100	1.0000	$29,371.72	$5,342.19
1952	71.50	$102,589.66	50.00	5.27	0.1054	1.0000	$10,813.41	$2,051.79
1951	72.50	$86,067.10	50.00	5.05	0.1009	1.0000	$8,685.20	$1,721.34
1950	73.50	$228,385.35	50.00	4.82	0.0965	1.0000	$22,033.51	$4,567.71
1949	74.50	$253,383.50	50.00	4.60	0.0921	1.0000	$23,334.36	$5,067.67
1948	75.50	$154,392.33	50.00	4.39	0.0877	1.0000	$13,546.72	$3,087.85
1947	76.50	$2,655,359.35	50.00	4.17	0.0834	1.0000	$221,485.36	$53,107.19
1946	77.50	$18,680.47	50.00	3.95	0.0791	1.0000	$1,476.92	$373.61
1945	78.50	$3,782.78	50.00	3.73	0.0747	1.0000	$282.40	$75.66
1944	79.50	$130,293.48	50.00	3.51	0.0701	1.0000	$9,138.36	$2,605.87
1943	80.50	$44,372.37	50.00	3.27	0.0655	1.0000	$2,904.38	$887.45
1942	81.50	$304,933.81	50.00	3.03	0.0606	1.0000	$18,464.99	$6,098.68
1941	82.50	$9,645.76	50.00	2.77	0.0554	1.0000	$534.51	$192.92
1940	83.50	$4,558.58	50.00	2.50	0.0501	1.0000	$228.24	$91.17
1939	84.50	$3,127.65	50.00	2.23	0.0446	1.0000	$139.57	$62.55
1938	85.50	$8,968.05	50.00	1.96	0.0392	1.0000	$351.88	$179.36
1937	86.50	$192.77	50.00	1.70	0.0340	1.0000	$6.55	$3.86
1936	87.50	$155.83	50.00	1.44	0.0288	1.0000	$4.49	$3.12
1935	88.50	$2,714.24	50.00	1.20	0.0239	1.0000	$64.89	$54.28
1934	89.50	$1,538.78	50.00	0.96	0.0193	1.0000	$29.65	$30.78
1933	90.50	$2,752.59	50.00	0.77	0.0154	1.0000	$42.29	$55.05
1932	91.50	$71,616.95	50.00	0.64	0.0128	1.0000	$917.40	$1,432.34
1931	92.50	$91,044.93	50.00	0.25	0.0050	1.0000	$454.98	$1,820.90
1930	93.50	$48,526.76	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1929	94.50	$176,886.71	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1928	95.50	$37,256.01	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1927	96.50	$87,775.76	50.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

PECO Elect 361 Composite 2024

Account: PECO Elect 361 Composite
Dispersion: 50.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1926	97.50	$82,891.61	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1925	98.50	$191,558.10	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1924	99.50	$976.73	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1923	100.50	$10,498.06	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1922	101.50	$2,610.73	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1920	103.50	$145.31	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1918	105.50	$66.74	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1917	106.50	$436,865.41	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1916	107.50	$233.39	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1915	108.50	$425.69	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1914	109.50	$35,532.28	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1913	110.50	$37.99	50.00	0.00	0.0000	0.0000	$0.00	$0.00
		$208,819,321.66	50.00	38.28	0.7615	1.0000	$159,019,196.13	$4,154,140.69

Remaining Life Depreciation Accrual

Account: PECO Elect 361 Composite
Scenario: PECO Elect 361 Composite 2024
Dispersion: 50.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$208,819,321.66	38.28	$4,220,813.11	2.021275%	2.612352%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($2,755,811.67)	0.50	($27,558.12)	1.000000%	
Total:	$208,819,321.66 *		$4,193,254.99	2.008078%	2.595295%
Average:	$207,441,415.83		$4,193,254.99	2.021416%	2.617619%
Grand Total:	$208,819,321.66 *		$4,193,254.99	2.008078%	2.595295%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elec 362.0 Composite 2024

Account: PECO Elec 362.0 Composite
Dispersion: 53.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$10,529,230.12	53.00	52.51	0.9907	1.0000	$10,431,369.04	$198,664.72
2022	1.50	$67,024,832.71	53.00	51.52	0.9722	1.0000	$65,159,467.66	$1,264,619.49
2021	2.50	$66,549,567.42	53.00	50.54	0.9537	1.0000	$63,465,963.05	$1,255,652.22
2020	3.50	$14,864,628.71	53.00	49.57	0.9352	1.0000	$13,901,506.15	$280,464.69
2019	4.50	$46,885,753.17	53.00	48.59	0.9168	1.0000	$42,986,438.00	$884,636.85
2018	5.50	$38,113,683.42	53.00	47.62	0.8985	1.0000	$34,245,315.69	$719,126.10
2017	6.50	$37,597,221.81	53.00	46.65	0.8802	1.0000	$33,094,641.05	$709,381.54
2016	7.50	$43,034,821.76	53.00	45.69	0.8621	1.0000	$37,098,217.49	$811,977.77
2015	8.50	$36,644,130.86	53.00	44.73	0.8439	1.0000	$30,925,395.17	$691,398.70
2014	9.50	$28,771,314.95	53.00	43.77	0.8259	1.0000	$23,762,657.29	$542,855.00
2013	10.50	$19,331,889.58	53.00	42.82	0.8080	1.0000	$15,619,672.39	$364,752.63
2012	11.50	$16,648,339.00	53.00	41.88	0.7901	1.0000	$13,154,469.42	$314,119.60
2011	12.50	$50,558,880.13	53.00	40.94	0.7724	1.0000	$39,051,238.29	$953,941.13
2010	13.50	$27,613,058.32	53.00	40.00	0.7548	1.0000	$20,841,757.87	$521,001.10
2009	14.50	$28,448,250.72	53.00	39.08	0.7373	1.0000	$20,974,001.50	$536,759.45
2008	15.50	$39,609,668.14	53.00	38.15	0.7199	1.0000	$28,513,933.24	$747,352.23
2007	16.50	$31,929,599.48	53.00	37.24	0.7026	1.0000	$22,433,831.86	$602,445.27
2006	17.50	$31,445,731.68	53.00	36.33	0.6855	1.0000	$21,554,830.44	$593,315.69
2005	18.50	$10,254,408.76	53.00	35.43	0.6685	1.0000	$6,854,653.46	$193,479.41
2004	19.50	$17,259,451.80	53.00	34.53	0.6516	1.0000	$11,246,135.70	$325,650.03
2003	20.50	$16,806,558.95	53.00	33.65	0.6349	1.0000	$10,670,057.16	$317,104.89
2002	21.50	$7,383,468.73	53.00	32.77	0.6183	1.0000	$4,565,246.95	$139,310.73
2001	22.50	$32,490,289.42	53.00	31.90	0.6019	1.0000	$19,556,629.74	$613,024.33
2000	23.50	$10,817,401.10	53.00	31.04	0.5857	1.0000	$6,335,494.74	$204,101.91
1999	24.50	$13,352,570.60	53.00	30.19	0.5696	1.0000	$7,605,561.75	$251,935.29
1998	25.50	$30,180,276.87	53.00	29.34	0.5537	1.0000	$16,710,147.32	$569,439.19
1997	26.50	$7,418,640.91	53.00	28.51	0.5379	1.0000	$3,990,692.83	$139,974.36
1996	27.50	$18,359,669.83	53.00	27.68	0.5224	1.0000	$9,590,284.21	$346,408.86
1995	28.50	$15,291,684.41	53.00	26.87	0.5070	1.0000	$7,752,291.46	$288,522.35
1994	29.50	$6,913,287.78	53.00	26.06	0.4917	1.0000	$3,399,582.08	$130,439.39
1993	30.50	$28,934,244.91	53.00	25.27	0.4767	1.0000	$13,793,544.23	$545,929.15
1992	31.50	$32,936,303.35	53.00	24.48	0.4619	1.0000	$15,214,146.20	$621,439.69

Generation Arrangement Report

PECO Elec 362.0 Composite 2024

Account: PECO Elec 362.0 Composite
Dispersion: 53.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$24,152,848.29	53.00	23.71	0.4473	1.0000	$10,803,454.62	$455,714.12
1990	33.50	$37,848,651.22	53.00	22.94	0.4329	1.0000	$16,383,079.99	$714,125.49
1989	34.50	$29,523,095.52	53.00	22.19	0.4186	1.0000	$12,359,082.73	$557,039.54
1988	35.50	$26,507,178.13	53.00	21.44	0.4046	1.0000	$10,724,806.20	$500,135.44
1987	36.50	$14,944,198.41	53.00	20.71	0.3908	1.0000	$5,840,117.08	$281,966.01
1986	37.50	$8,196,919.29	53.00	19.99	0.3772	1.0000	$3,091,943.38	$154,658.85
1985	38.50	$6,561,855.92	53.00	19.28	0.3638	1.0000	$2,387,522.48	$123,808.60
1984	39.50	$7,825,005.49	53.00	18.59	0.3507	1.0000	$2,744,469.82	$147,641.61
1983	40.50	$4,100,581.72	53.00	17.91	0.3379	1.0000	$1,385,667.20	$77,369.47
1982	41.50	$1,623,238.28	53.00	17.24	0.3253	1.0000	$528,070.04	$30,627.14
1981	42.50	$4,706,056.59	53.00	16.59	0.3130	1.0000	$1,472,911.15	$88,793.52
1980	43.50	$2,380,638.59	53.00	15.95	0.3009	1.0000	$716,384.64	$44,917.71
1979	44.50	$3,893,327.88	53.00	15.32	0.2891	1.0000	$1,125,723.76	$73,459.02
1978	45.50	$1,190,460.06	53.00	14.72	0.2777	1.0000	$330,542.67	$22,461.51
1977	46.50	$2,818,954.60	53.00	14.12	0.2665	1.0000	$751,191.18	$53,187.82
1976	47.50	$539,449.08	53.00	13.55	0.2556	1.0000	$137,889.03	$10,178.28
1975	48.50	$9,257,226.00	53.00	12.99	0.2451	1.0000	$2,268,578.18	$174,664.64
1974	49.50	$14,961,493.78	53.00	12.45	0.2349	1.0000	$3,514,499.39	$282,292.34
1973	50.50	$7,486,574.36	53.00	11.93	0.2250	1.0000	$1,684,659.18	$141,256.12
1972	51.50	$15,790,644.56	53.00	11.42	0.2155	1.0000	$3,402,628.86	$297,936.69
1971	52.50	$15,932,126.01	53.00	10.93	0.2063	1.0000	$3,286,473.22	$300,606.15
1970	53.50	$11,490,888.66	53.00	10.46	0.1974	1.0000	$2,268,501.26	$216,809.22
1969	54.50	$14,545,700.97	53.00	10.01	0.1889	1.0000	$2,747,595.04	$274,447.19
1968	55.50	$7,277,157.65	53.00	9.58	0.1807	1.0000	$1,315,030.80	$137,304.86
1967	56.50	$6,574,253.17	53.00	9.16	0.1729	1.0000	$1,136,378.76	$124,042.51
1966	57.50	$3,866,856.62	53.00	8.76	0.1653	1.0000	$639,314.18	$72,959.56
1965	58.50	$3,363,084.47	53.00	8.38	0.1581	1.0000	$531,739.93	$63,454.42
1964	59.50	$4,195,485.97	53.00	8.01	0.1512	1.0000	$634,336.77	$79,160.11
1963	60.50	$5,635,112.60	53.00	7.66	0.1446	1.0000	$814,636.61	$106,322.88
1962	61.50	$3,161,115.24	53.00	7.33	0.1382	1.0000	$436,902.73	$59,643.68
1961	62.50	$5,074,031.11	53.00	7.00	0.1321	1.0000	$670,361.92	$95,736.44
1960	63.50	$5,123,027.63	53.00	6.69	0.1263	1.0000	$646,872.53	$96,660.90

Generation Arrangement Report

PECO Elec 362.0 Composite 2024

Account: PECO Elec 362.0 Composite
Dispersion: 53.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1959	64.50	$4,830,558.65	53.00	6.39	0.1206	1.0000	$582,723.60	$91,142.62
1958	65.50	$5,450,535.77	53.00	6.11	0.1152	1.0000	$627,931.79	$102,840.30
1957	66.50	$3,768,437.20	53.00	5.82	0.1098	1.0000	$413,779.12	$71,102.59
1956	67.50	$5,104,223.15	53.00	5.55	0.1046	1.0000	$534,025.48	$96,306.10
1955	68.50	$2,735,674.13	53.00	5.28	0.0996	1.0000	$272,362.04	$51,616.49
1954	69.50	$3,476,424.75	53.00	5.01	0.0946	1.0000	$328,824.96	$65,592.92
1953	70.50	$3,285,379.59	53.00	4.75	0.0897	1.0000	$294,635.52	$61,988.29
1952	71.50	$1,191,717.26	53.00	4.50	0.0848	1.0000	$101,089.60	$22,485.23
1951	72.50	$1,631,543.86	53.00	4.24	0.0800	1.0000	$130,539.05	$30,783.85
1950	73.50	$1,626,157.53	53.00	3.99	0.0752	1.0000	$122,327.01	$30,682.22
1949	74.50	$1,496,072.73	53.00	3.73	0.0705	1.0000	$105,430.13	$28,227.79
1948	75.50	$625,523.85	53.00	3.47	0.0654	1.0000	$40,922.60	$11,802.34
1947	76.50	$3,993,323.41	53.00	3.21	0.0606	1.0000	$241,874.74	$75,345.72
1946	77.50	$167,269.88	53.00	2.95	0.0557	1.0000	$9,322.67	$3,156.04
1945	78.50	$878,738.76	53.00	2.70	0.0509	1.0000	$44,754.73	$16,579.98
1944	79.50	$347,494.40	53.00	2.45	0.0462	1.0000	$16,046.21	$6,556.50
1943	80.50	$232,701.63	53.00	2.20	0.0415	1.0000	$9,658.00	$4,390.60
1942	81.50	$1,136,887.35	53.00	1.96	0.0369	1.0000	$41,999.64	$21,450.70
1941	82.50	$150,879.56	53.00	1.73	0.0326	1.0000	$4,914.79	$2,846.78
1940	83.50	$79,699.91	53.00	1.51	0.0285	1.0000	$2,272.94	$1,503.77
1939	84.50	$63,228.30	53.00	1.26	0.0237	1.0000	$1,501.26	$1,192.99
1938	85.50	$34,242.24	53.00	1.04	0.0195	1.0000	$668.89	$646.08
1937	86.50	$34,836.70	53.00	0.82	0.0155	1.0000	$539.64	$657.30
1936	87.50	$761.29	53.00	0.61	0.0116	1.0000	$8.80	$14.36
1934	89.50	$14.16	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1933	90.50	$6,421.78	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1932	91.50	$1,720,287.31	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1931	92.50	$207,345.79	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1930	93.50	$218,536.19	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1929	94.50	$1,036,574.56	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1928	95.50	$43,170.87	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1927	96.50	$31,124.00	53.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

PECO Elec 362.0 Composite 2024

Account: PECO Elec 362.0 Composite
Dispersion: 53.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1926	97.50	$70,604.00	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1925	98.50	$253,046.25	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1924	99.50	$685,355.55	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1923	100.50	$697,046.71	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1922	101.50	$3,115.13	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1921	102.50	$2,243.02	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1920	103.50	$53,262.69	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1919	104.50	$411.69	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1917	106.50	$1,947.98	53.00	0.00	0.0000	0.0000	$0.00	$0.00
1916	107.50	$18,245.30	53.00	0.00	0.0000	0.0000	$0.00	$0.00
		$1,241,937,162.15	53.00	33.22	0.6242	1.0000	$775,208,691.97	$23,337,517.15

Remaining Life Depreciation Accrual

Account: PECO Elec 362.0 Composite
Scenario: PECO Elec 362.0 Composite 2024
Dispersion: 53.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,241,937,162.15	33.22	$22,000,264.65	1.771447%	3.010482%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($18,840,661.55)	0.50	($177,742.09)	0.943396%	
Total:	$1,241,937,162.15 *		$21,822,522.56	1.757136%	2.986160%
Average:	$1,232,516,831.38		$21,822,522.56	1.770566%	3.025156%
Grand Total:	$1,241,937,162.15 *		$21,822,522.56	1.757136%	2.986160%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elect 364 Composite 2024

Account: PECO Electric 3640 PA
Dispersion: 53.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$112,707,057.31	53.00	52.55	0.9915	1.0000	$111,744,218.07	$2,126,548.25
2022	1.50	$99,070,409.08	53.00	51.64	0.9744	1.0000	$96,536,971.65	$1,869,253.00
2021	2.50	$108,421,744.39	53.00	50.75	0.9575	1.0000	$103,813,873.37	$2,045,693.29
2020	3.50	$107,095,833.40	53.00	49.86	0.9407	1.0000	$100,740,941.19	$2,020,676.10
2019	4.50	$73,293,942.61	53.00	48.97	0.9239	1.0000	$67,718,249.03	$1,382,904.58
2018	5.50	$53,385,034.92	53.00	48.09	0.9073	1.0000	$48,435,137.11	$1,007,264.81
2017	6.50	$29,621,912.49	53.00	47.21	0.8907	1.0000	$26,385,280.05	$558,904.01
2016	7.50	$25,442,392.03	53.00	46.34	0.8743	1.0000	$22,244,081.18	$480,045.13
2015	8.50	$24,572,184.84	53.00	45.47	0.8580	1.0000	$21,081,749.48	$463,626.13
2014	9.50	$26,229,610.31	53.00	44.61	0.8417	1.0000	$22,077,901.93	$494,898.31
2013	10.50	$20,349,552.47	53.00	43.76	0.8256	1.0000	$16,800,414.99	$383,953.82
2012	11.50	$21,912,501.68	53.00	42.91	0.8096	1.0000	$17,739,863.60	$413,443.43
2011	12.50	$26,063,770.03	53.00	42.06	0.7937	1.0000	$20,686,266.56	$491,769.25
2010	13.50	$22,595,863.39	53.00	41.23	0.7779	1.0000	$17,577,812.88	$426,337.05
2009	14.50	$14,729,645.88	53.00	40.40	0.7623	1.0000	$11,227,896.88	$277,917.85
2008	15.50	$19,956,251.27	53.00	39.58	0.7467	1.0000	$14,901,870.46	$376,533.04
2007	16.50	$15,411,860.62	53.00	38.76	0.7313	1.0000	$11,270,909.90	$290,789.82
2006	17.50	$20,159,579.94	53.00	37.95	0.7160	1.0000	$14,434,698.03	$380,369.43
2005	18.50	$20,711,272.66	53.00	37.15	0.7009	1.0000	$14,515,672.54	$390,778.73
2004	19.50	$10,049,382.93	53.00	36.35	0.6858	1.0000	$6,892,195.34	$189,611.00
2003	20.50	$27,043,569.90	53.00	35.56	0.6709	1.0000	$18,144,320.68	$510,256.04
2002	21.50	$25,561,069.58	53.00	34.78	0.6562	1.0000	$16,772,290.16	$482,284.33
2001	22.50	$35,501,510.23	53.00	34.00	0.6416	1.0000	$22,776,855.38	$669,839.82
2000	23.50	$7,302,656.96	53.00	33.24	0.6271	1.0000	$4,579,444.54	$137,785.98
1999	24.50	$18,900,971.04	53.00	32.48	0.6128	1.0000	$11,581,735.98	$356,622.10
1998	25.50	$14,403,361.27	53.00	31.72	0.5986	1.0000	$8,621,425.61	$271,761.53
1997	26.50	$11,769,155.91	53.00	30.98	0.5845	1.0000	$6,879,389.59	$222,059.55
1996	27.50	$15,619,911.58	53.00	30.24	0.5706	1.0000	$8,913,248.45	$294,715.31
1995	28.50	$8,871,896.23	53.00	29.52	0.5569	1.0000	$4,940,674.65	$167,394.27
1994	29.50	$8,742,214.88	53.00	28.80	0.5433	1.0000	$4,749,745.67	$164,947.45
1993	30.50	$11,704,749.42	53.00	28.08	0.5299	1.0000	$6,202,216.84	$220,844.33
1992	31.50	$10,705,719.50	53.00	27.38	0.5167	1.0000	$5,531,225.16	$201,994.71

Generation Arrangement Report

PECO Elect 364 Composite 2024

Account: PECO Electric 3640 PA
Dispersion: 53.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$7,701,316.66	53.00	26.69	0.5036	1.0000	$3,878,184.97	$145,307.86
1990	33.50	$9,705,601.97	53.00	26.00	0.4907	1.0000	$4,762,117.60	$183,124.57
1989	34.50	$10,821,176.25	53.00	25.33	0.4779	1.0000	$5,171,522.41	$204,173.14
1988	35.50	$8,679,787.23	53.00	24.66	0.4653	1.0000	$4,038,995.56	$163,769.57
1987	36.50	$9,674,325.58	53.00	24.01	0.4529	1.0000	$4,381,849.40	$182,534.44
1986	37.50	$7,703,983.59	53.00	23.36	0.4407	1.0000	$3,395,266.93	$145,358.18
1985	38.50	$6,659,520.61	53.00	22.72	0.4287	1.0000	$2,854,803.15	$125,651.33
1984	39.50	$5,095,433.81	53.00	22.09	0.4168	1.0000	$2,123,958.74	$96,140.26
1983	40.50	$3,580,143.66	53.00	21.48	0.4052	1.0000	$1,450,755.17	$67,549.88
1982	41.50	$3,583,438.75	53.00	20.87	0.3938	1.0000	$1,411,020.57	$67,612.05
1981	42.50	$2,952,296.97	53.00	20.27	0.3825	1.0000	$1,129,267.27	$55,703.72
1980	43.50	$2,548,672.48	53.00	19.69	0.3714	1.0000	$946,672.17	$48,088.16
1979	44.50	$2,347,544.54	53.00	19.11	0.3606	1.0000	$846,469.34	$44,293.29
1978	45.50	$2,474,919.17	53.00	18.55	0.3499	1.0000	$866,013.48	$46,696.59
1977	46.50	$2,325,337.03	53.00	17.99	0.3395	1.0000	$789,358.88	$43,874.28
1976	47.50	$1,817,440.01	53.00	17.45	0.3292	1.0000	$598,322.06	$34,291.32
1975	48.50	$1,820,147.61	53.00	16.92	0.3192	1.0000	$580,948.70	$34,342.41
1974	49.50	$2,658,847.79	53.00	16.40	0.3094	1.0000	$822,597.71	$50,166.94
1973	50.50	$2,161,228.03	53.00	15.89	0.2998	1.0000	$647,877.14	$40,777.89
1972	51.50	$1,793,036.32	53.00	15.39	0.2904	1.0000	$520,645.79	$33,830.87
1971	52.50	$1,709,705.13	53.00	14.90	0.2812	1.0000	$480,745.80	$32,258.59
1970	53.50	$2,480,850.89	53.00	14.43	0.2722	1.0000	$675,318.44	$46,808.51
1969	54.50	$2,429,974.29	53.00	13.96	0.2634	1.0000	$640,175.73	$45,848.57
1968	55.50	$1,330,661.00	53.00	13.51	0.2549	1.0000	$339,180.80	$25,106.81
1967	56.50	$898,537.90	53.00	13.07	0.2466	1.0000	$221,536.09	$16,953.55
1966	57.50	$714,773.16	53.00	12.64	0.2384	1.0000	$170,423.65	$13,486.29
1964	59.50	$925,992.75	53.00	11.81	0.2228	1.0000	$206,280.81	$17,471.56
1963	60.50	$822,908.01	53.00	11.41	0.2152	1.0000	$177,120.00	$15,526.57
1962	61.50	$823,378.71	53.00	11.02	0.2079	1.0000	$171,173.02	$15,535.45
1961	62.50	$949,545.05	53.00	10.64	0.2007	1.0000	$190,606.18	$17,915.94
1960	63.50	$821,494.24	53.00	10.27	0.1938	1.0000	$159,174.62	$15,499.89
1959	64.50	$570,339.86	53.00	9.91	0.1870	1.0000	$106,633.16	$10,761.13

Generation Arrangement Report

PECO Elect 364 Composite 2024

Account: PECO Electric 3640 PA
Dispersion: 53.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1958	65.50	$924,079.67	53.00	9.56	0.1803	1.0000	$166,642.87	$17,435.47
1957	66.50	$393,614.71	53.00	9.21	0.1738	1.0000	$68,416.98	$7,426.69
1956	67.50	$368,983.67	53.00	8.88	0.1675	1.0000	$61,794.63	$6,961.96
1955	68.50	$282,786.60	53.00	8.55	0.1613	1.0000	$45,604.74	$5,335.60
1954	69.50	$215,707.90	53.00	8.22	0.1552	1.0000	$33,475.25	$4,069.96
1953	70.50	$144,466.50	53.00	7.91	0.1492	1.0000	$21,557.74	$2,725.78
1951	72.50	$132,414.25	53.00	7.29	0.1376	1.0000	$18,219.07	$2,498.38
1950	73.50	$70,094.28	53.00	6.99	0.1319	1.0000	$9,246.47	$1,322.53
1949	74.50	$82,823.93	53.00	6.69	0.1263	1.0000	$10,460.66	$1,562.72
1948	75.50	$52,439.79	53.00	6.39	0.1206	1.0000	$6,325.30	$989.43
1947	76.50	$22,493.60	53.00	6.10	0.1151	1.0000	$2,588.10	$424.41
1946	77.50	$21,182.55	53.00	5.81	0.1095	1.0000	$2,320.28	$399.67
1945	78.50	$18,741.49	53.00	5.51	0.1040	1.0000	$1,949.86	$353.61
1944	79.50	$17,123.36	53.00	5.22	0.0986	1.0000	$1,687.76	$323.08
1943	80.50	$12,172.47	53.00	4.93	0.0931	1.0000	$1,133.38	$229.67
1942	81.50	$71,377.49	53.00	4.65	0.0877	1.0000	$6,258.19	$1,346.75
1941	82.50	($9,403.11)	53.00	4.36	0.0823	1.0000	($773.60)	($177.42)
1939	84.50	$1,637.10	53.00	3.78	0.0713	1.0000	$116.75	$30.89
1938	85.50	$2,324.56	53.00	3.49	0.0659	1.0000	$153.22	$43.86
1937	86.50	$896.01	53.00	3.21	0.0605	1.0000	$54.25	$16.91
1936	87.50	$1,588.79	53.00	2.93	0.0552	1.0000	$87.75	$29.98
1935	88.50	$1,062.65	53.00	2.65	0.0500	1.0000	$53.12	$20.05
1934	89.50	$400.00	53.00	2.38	0.0448	1.0000	$17.93	$7.55
1933	90.50	$202.73	53.00	2.11	0.0398	1.0000	$8.07	$3.83
1932	91.50	$95.92	53.00	1.85	0.0349	1.0000	$3.35	$1.81
1931	92.50	$104.73	53.00	1.61	0.0304	1.0000	$3.18	$1.98
1930	93.50	$69.86	53.00	1.34	0.0252	1.0000	$1.76	$1.32
1929	94.50	$106.13	53.00	1.09	0.0207	1.0000	$2.19	$2.00
1928	95.50	$8.61	53.00	0.87	0.0164	1.0000	$0.14	$0.16
1924	99.50	($20,888.12)	53.00	0.00	0.0000	0.0000	$0.00	$0.00
		$1,161,297,655.92	53.00	42.52	0.8023	1.0000	$931,731,001.69	$21,911,670.64

Remaining Life Depreciation Accrual

Account: PECO Electric 3640 PA
Scenario: PECO Elect 364 Composite 2024
Dispersion: 53.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,161,297,655.92	42.52	$24,856,519.89	2.140409%	2.351716%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($6,485,035.14)	0.50	($61,179.58)	0.943396%	
Total:	$1,161,297,655.92 *		$24,795,340.31	2.135141%	2.345928%
Average:	$1,158,055,138.35		$24,795,340.31	2.141119%	2.353147%
Grand Total:	$1,161,297,655.92 *		$24,795,340.31	2.135141%	2.345928%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elect 365 Composite 2024

Account: PECO Electric 3650 PA
Dispersion: 52.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$169,795,723.06	52.00	51.53	0.9909	1.0000	$168,252,287.67	$3,265,302.37
2022	1.50	$130,804,139.40	52.00	50.59	0.9728	1.0000	$127,245,055.33	$2,515,464.22
2021	2.50	$139,154,133.46	52.00	49.65	0.9547	1.0000	$132,854,557.46	$2,676,041.03
2020	3.50	$162,772,281.91	52.00	48.71	0.9367	1.0000	$152,476,292.93	$3,130,236.19
2019	4.50	$143,968,546.63	52.00	47.78	0.9188	1.0000	$132,284,362.57	$2,768,625.90
2018	5.50	$95,217,582.61	52.00	46.85	0.9010	1.0000	$85,791,824.21	$1,831,107.36
2017	6.50	$69,866,381.02	52.00	45.93	0.8833	1.0000	$61,710,777.36	$1,343,584.25
2016	7.50	$56,334,113.34	52.00	45.01	0.8656	1.0000	$48,765,356.04	$1,083,348.33
2015	8.50	$52,254,423.63	52.00	44.10	0.8481	1.0000	$44,316,467.08	$1,004,892.76
2014	9.50	$70,801,841.79	52.00	43.19	0.8306	1.0000	$58,810,299.49	$1,361,573.88
2013	10.50	$34,870,611.52	52.00	42.29	0.8133	1.0000	$28,359,579.76	$670,588.68
2012	11.50	$44,646,915.39	52.00	41.39	0.7960	1.0000	$35,540,288.14	$858,594.53
2011	12.50	$49,511,614.69	52.00	40.50	0.7789	1.0000	$38,564,151.59	$952,146.44
2010	13.50	$46,247,568.67	52.00	39.62	0.7619	1.0000	$35,234,788.58	$889,376.32
2009	14.50	$42,911,649.78	52.00	38.74	0.7450	1.0000	$31,967,874.04	$825,224.03
2008	15.50	$49,895,688.70	52.00	37.87	0.7282	1.0000	$36,333,431.65	$959,532.48
2007	16.50	$39,084,220.26	52.00	37.00	0.7115	1.0000	$27,809,881.08	$751,619.62
2006	17.50	$34,579,935.67	52.00	36.14	0.6950	1.0000	$24,033,544.24	$664,998.76
2005	18.50	$59,838,582.89	52.00	35.29	0.6786	1.0000	$40,608,209.63	$1,150,741.98
2004	19.50	$10,255,935.31	52.00	34.44	0.6624	1.0000	$6,793,428.31	$197,229.53
2003	20.50	$19,053,284.05	52.00	33.61	0.6463	1.0000	$12,314,522.90	$366,409.31
2002	21.50	$23,280,004.46	52.00	32.78	0.6304	1.0000	$14,675,147.33	$447,692.39
2001	22.50	$21,321,612.28	52.00	31.96	0.6146	1.0000	$13,103,929.97	$410,031.01
2000	23.50	$2,804,564.73	52.00	31.15	0.5989	1.0000	$1,679,778.36	$53,933.94
1999	24.50	$17,372,396.20	52.00	30.34	0.5835	1.0000	$10,136,177.40	$334,084.54
1998	25.50	$32,473,051.77	52.00	29.54	0.5681	1.0000	$18,449,445.84	$624,481.76
1997	26.50	$20,859,419.53	52.00	28.76	0.5530	1.0000	$11,535,132.03	$401,142.68
1996	27.50	$34,513,757.68	52.00	27.98	0.5380	1.0000	$18,568,982.65	$663,726.11
1995	28.50	$25,213,237.25	52.00	27.21	0.5232	1.0000	$13,191,636.13	$484,869.95
1994	29.50	$19,111,395.74	52.00	26.45	0.5086	1.0000	$9,719,589.21	$367,526.84
1993	30.50	$19,946,095.02	52.00	25.69	0.4941	1.0000	$9,855,813.93	$383,578.75
1992	31.50	$18,094,762.87	52.00	24.95	0.4799	1.0000	$8,682,872.06	$347,976.21

Generation Arrangement Report

PECO Elect 365 Composite 2024

Account: PECO Electric 3650 PA
Dispersion: 52.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$12,947,737.97	52.00	24.22	0.4658	1.0000	$6,030,808.28	$248,994.96
1990	33.50	$18,091,210.37	52.00	23.50	0.4520	1.0000	$8,176,331.11	$347,907.89
1989	34.50	$21,288,351.14	52.00	22.79	0.4383	1.0000	$9,330,261.32	$409,391.37
1988	35.50	$13,223,974.53	52.00	22.09	0.4248	1.0000	$5,617,713.33	$254,307.20
1987	36.50	$13,777,616.37	52.00	21.40	0.4116	1.0000	$5,670,311.95	$264,954.16
1986	37.50	$9,467,448.47	52.00	20.72	0.3985	1.0000	$3,772,983.94	$182,066.32
1985	38.50	$7,769,869.46	52.00	20.06	0.3857	1.0000	$2,996,929.61	$149,420.57
1984	39.50	$6,960,443.79	52.00	19.40	0.3731	1.0000	$2,597,171.54	$133,854.69
1983	40.50	$4,917,679.98	52.00	18.76	0.3608	1.0000	$1,774,271.18	$94,570.77
1982	41.50	$4,971,953.82	52.00	18.13	0.3487	1.0000	$1,733,748.98	$95,614.50
1981	42.50	$5,139,440.79	52.00	17.52	0.3369	1.0000	$1,731,367.80	$98,835.40
1980	43.50	$5,382,127.90	52.00	16.92	0.3253	1.0000	$1,750,861.61	$103,502.46
1979	44.50	$4,545,014.38	52.00	16.33	0.3140	1.0000	$1,427,216.54	$87,404.12
1978	45.50	$3,839,619.81	52.00	15.76	0.3030	1.0000	$1,163,445.71	$73,838.84
1977	46.50	$3,236,715.81	52.00	15.20	0.2924	1.0000	$946,271.23	$62,244.53
1976	47.50	$3,525,207.59	52.00	14.66	0.2819	1.0000	$993,927.06	$67,792.45
1975	48.50	$3,222,432.51	52.00	14.14	0.2719	1.0000	$876,019.78	$61,969.86
1974	49.50	$4,999,282.54	52.00	13.63	0.2621	1.0000	$1,310,125.60	$96,140.05
1973	50.50	$4,810,568.42	52.00	13.13	0.2526	1.0000	$1,215,126.85	$92,510.93
1972	51.50	$3,535,812.19	52.00	12.66	0.2434	1.0000	$860,774.15	$67,996.39
1971	52.50	$3,828,272.10	52.00	12.20	0.2346	1.0000	$898,180.92	$73,620.62
1970	53.50	$5,476,284.30	52.00	11.76	0.2261	1.0000	$1,238,293.75	$105,313.16
1969	54.50	$5,399,737.81	52.00	11.33	0.2179	1.0000	$1,176,820.72	$103,841.11
1968	55.50	$2,531,722.85	52.00	10.92	0.2101	1.0000	$531,871.23	$48,686.98
1967	56.50	$2,174,687.12	52.00	10.53	0.2025	1.0000	$440,471.05	$41,820.91
1966	57.50	$1,925,518.22	52.00	10.16	0.1953	1.0000	$376,078.45	$37,029.20
1965	58.50	$1,600,694.23	52.00	9.80	0.1884	1.0000	$301,542.85	$30,782.58
1964	59.50	$3,080,596.56	52.00	9.45	0.1817	1.0000	$559,797.66	$59,242.24
1963	60.50	$2,409,061.97	52.00	9.12	0.1753	1.0000	$422,390.91	$46,328.11
1962	61.50	$1,719,745.88	52.00	8.80	0.1692	1.0000	$291,003.48	$33,072.04
1961	62.50	$2,155,648.30	52.00	8.49	0.1633	1.0000	$352,080.16	$41,454.78
1960	63.50	$1,250,050.88	52.00	8.20	0.1577	1.0000	$197,093.45	$24,039.44

Generation Arrangement Report

PECO Elect 365 Composite 2024

Account: PECO Electric 3650 PA
Dispersion: 52.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1959	64.50	$858,350.60	52.00	7.92	0.1522	1.0000	$130,651.01	$16,506.74
1958	65.50	$504,103.68	52.00	7.64	0.1469	1.0000	$74,073.59	$9,694.30
1957	66.50	$382,370.58	52.00	7.38	0.1418	1.0000	$54,235.73	$7,353.28
1956	67.50	$293,368.64	52.00	7.12	0.1369	1.0000	$40,154.65	$5,641.70
1955	68.50	$99,990.06	52.00	6.87	0.1321	1.0000	$13,203.96	$1,922.89
1954	69.50	$31,317.39	52.00	6.62	0.1273	1.0000	$3,987.60	$602.26
1953	70.50	$49,990.08	52.00	6.38	0.1227	1.0000	$6,134.39	$961.35
1952	71.50	$24,309.17	52.00	6.15	0.1182	1.0000	$2,872.82	$467.48
1951	72.50	$152,521.60	52.00	5.90	0.1135	1.0000	$17,315.76	$2,933.11
1950	73.50	$79,637.06	52.00	5.67	0.1091	1.0000	$8,687.40	$1,531.48
1949	74.50	$53,559.85	52.00	5.44	0.1047	1.0000	$5,608.11	$1,030.00
1948	75.50	$14,399.30	52.00	5.22	0.1004	1.0000	$1,445.50	$276.91
1947	76.50	$8,427.57	52.00	5.00	0.0961	1.0000	$810.07	$162.07
1946	77.50	$8,086.86	52.00	4.78	0.0919	1.0000	$743.24	$155.52
1945	78.50	$3,874.24	52.00	4.56	0.0877	1.0000	$339.89	$74.50
1944	79.50	$3,350.66	52.00	4.35	0.0836	1.0000	$280.04	$64.44
1943	80.50	$1,711.43	52.00	4.13	0.0794	1.0000	$135.92	$32.91
1942	81.50	$62,374.90	52.00	3.91	0.0752	1.0000	$4,692.37	$1,199.52
1941	82.50	($72,292.11)	52.00	3.69	0.0710	1.0000	($5,129.80)	($1,390.23)
1940	83.50	$555.22	52.00	3.46	0.0666	1.0000	$36.96	$10.68
1939	84.50	$810.69	52.00	3.22	0.0620	1.0000	$50.28	$15.59
1938	85.50	$5.91	52.00	2.96	0.0568	1.0000	$0.34	$0.11
1937	86.50	$2.82	52.00	2.69	0.0517	1.0000	$0.15	$0.05
1936	87.50	$1.25	52.00	2.42	0.0465	1.0000	$0.06	$0.02
1935	88.50	$0.97	52.00	2.15	0.0413	1.0000	$0.04	$0.02
1934	89.50	$1.11	52.00	1.88	0.0361	1.0000	$0.04	$0.02
1933	90.50	$0.95	52.00	1.61	0.0310	1.0000	$0.03	$0.02
1932	91.50	$0.60	52.00	1.36	0.0261	1.0000	$0.02	$0.01
1931	92.50	$0.99	52.00	1.11	0.0214	1.0000	$0.02	$0.02
		$1,948,620,831.44	52.00	40.74	0.7835	1.0000	$1,526,787,107.32	$37,473,477.53

Remaining Life Depreciation Accrual

Account: PECO Electric 3650 PA
Scenario: PECO Elect 365 Composite 2024
Dispersion: 52.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,948,620,831.44	40.74	$40,425,207.64	2.074555%	2.454401%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($10,328,658.16)	0.50	($99,314.02)	0.961538%	
Total:	$1,948,620,831.44 *		$40,325,893.62	2.069458%	2.448371%
Average:	$1,943,456,502.36		$40,325,893.62	2.074957%	2.456072%
Grand Total:	$1,948,620,831.44 *		$40,325,893.62	2.069458%	2.448371%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elect 366 Composite 2024

Account: PECO Electric 3660 PA
Dispersion: 70.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$97,252,375.89	70.00	69.50	0.9929	1.0000	$96,558,406.94	$1,389,319.66
2022	1.50	$88,606,554.80	70.00	68.50	0.9786	1.0000	$86,709,720.51	$1,265,807.93
2021	2.50	$59,646,970.28	70.00	67.50	0.9643	1.0000	$57,518,564.74	$852,099.58
2020	3.50	$34,662,319.03	70.00	66.50	0.9501	1.0000	$32,931,222.27	$495,175.99
2019	4.50	$51,382,205.42	70.00	65.51	0.9358	1.0000	$48,082,956.59	$734,031.51
2018	5.50	$29,015,563.93	70.00	64.51	0.9215	1.0000	$26,739,007.37	$414,508.06
2017	6.50	$14,766,832.37	70.00	63.51	0.9073	1.0000	$13,397,698.74	$210,954.75
2016	7.50	$26,537,646.87	70.00	62.51	0.8930	1.0000	$23,699,007.28	$379,109.24
2015	8.50	$20,327,221.64	70.00	61.52	0.8788	1.0000	$17,863,555.69	$290,388.88
2014	9.50	$14,049,435.94	70.00	60.52	0.8646	1.0000	$12,146,808.48	$200,706.23
2013	10.50	$8,888,240.06	70.00	59.52	0.8504	1.0000	$7,558,130.89	$126,974.86
2012	11.50	$7,897,493.70	70.00	58.53	0.8361	1.0000	$6,603,426.22	$112,821.34
2011	12.50	$16,308,130.45	70.00	57.54	0.8219	1.0000	$13,404,388.94	$232,973.29
2010	13.50	$7,734,422.17	70.00	56.54	0.8078	1.0000	$6,247,608.01	$110,491.75
2009	14.50	$12,643,841.36	70.00	55.55	0.7936	1.0000	$10,034,238.75	$180,626.31
2008	15.50	$4,876,257.04	70.00	54.56	0.7795	1.0000	$3,800,839.14	$69,660.81
2007	16.50	$11,780,516.11	70.00	53.57	0.7653	1.0000	$9,016,015.24	$168,293.09
2006	17.50	$5,013,122.31	70.00	52.59	0.7512	1.0000	$3,766,015.31	$71,616.03
2005	18.50	$5,710,040.79	70.00	51.60	0.7372	1.0000	$4,209,224.76	$81,572.01
2004	19.50	$4,264,641.89	70.00	50.62	0.7231	1.0000	$3,083,815.52	$60,923.46
2003	20.50	$9,067,915.43	70.00	49.64	0.7091	1.0000	$6,430,072.45	$129,541.65
2002	21.50	$7,194,922.66	70.00	48.66	0.6951	1.0000	$5,001,345.70	$102,784.61
2001	22.50	$14,914,911.56	70.00	47.68	0.6812	1.0000	$10,159,813.13	$213,070.17
2000	23.50	$920,312.23	70.00	46.71	0.6673	1.0000	$614,106.07	$13,147.32
1999	24.50	$2,533,362.12	70.00	45.74	0.6534	1.0000	$1,655,399.49	$36,190.89
1998	25.50	$3,094,409.53	70.00	44.78	0.6396	1.0000	$1,979,332.54	$44,205.85
1997	26.50	$5,521,743.94	70.00	43.81	0.6259	1.0000	$3,456,057.15	$78,882.06
1996	27.50	$5,183,353.37	70.00	42.86	0.6122	1.0000	$3,173,367.55	$74,047.91
1995	28.50	$5,299,542.42	70.00	41.90	0.5986	1.0000	$3,172,285.67	$75,707.75
1994	29.50	$3,396,149.35	70.00	40.95	0.5851	1.0000	$1,986,946.42	$48,516.42
1993	30.50	$7,755,053.76	70.00	40.01	0.5716	1.0000	$4,432,537.14	$110,786.48
1992	31.50	$3,732,844.01	70.00	39.07	0.5582	1.0000	$2,083,629.53	$53,326.34

Generation Arrangement Report

PECO Elect 366 Composite 2024

Account: PECO Electric 3660 PA
Dispersion: 70.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$4,237,570.63	70.00	38.14	0.5449	1.0000	$2,309,011.55	$60,536.72
1990	33.50	$17,866,908.59	70.00	37.22	0.5317	1.0000	$9,499,072.60	$255,241.55
1989	34.50	$5,751,864.11	70.00	36.30	0.5185	1.0000	$2,982,621.74	$82,169.49
1988	35.50	$5,176,366.85	70.00	35.39	0.5055	1.0000	$2,616,696.16	$73,948.10
1987	36.50	$6,204,778.29	70.00	34.48	0.4926	1.0000	$3,056,540.53	$88,639.69
1986	37.50	$2,938,268.66	70.00	33.58	0.4798	1.0000	$1,409,727.94	$41,975.27
1985	38.50	$2,730,375.12	70.00	32.70	0.4671	1.0000	$1,275,406.34	$39,005.36
1984	39.50	$3,121,229.90	70.00	31.82	0.4546	1.0000	$1,418,790.57	$44,589.00
1983	40.50	$2,629,856.61	70.00	30.95	0.4421	1.0000	$1,162,667.22	$37,569.38
1982	41.50	$2,318,478.63	70.00	30.09	0.4298	1.0000	$996,512.44	$33,121.12
1981	42.50	$2,597,572.27	70.00	29.23	0.4176	1.0000	$1,084,778.85	$37,108.18
1980	43.50	$1,961,537.57	70.00	28.39	0.4056	1.0000	$795,595.84	$28,021.97
1979	44.50	$1,986,558.39	70.00	27.56	0.3937	1.0000	$782,051.25	$28,379.41
1978	45.50	$1,025,003.05	70.00	26.74	0.3820	1.0000	$391,500.47	$14,642.90
1977	46.50	$1,362,058.73	70.00	25.93	0.3704	1.0000	$504,460.50	$19,457.98
1976	47.50	$4,636,588.74	70.00	25.12	0.3589	1.0000	$1,664,057.39	$66,236.98
1975	48.50	$2,386,156.92	70.00	24.33	0.3476	1.0000	$829,479.01	$34,087.96
1974	49.50	$4,445,319.26	70.00	23.55	0.3364	1.0000	$1,495,607.16	$63,504.56
1973	50.50	$3,753,484.97	70.00	22.78	0.3255	1.0000	$1,221,716.95	$53,621.21
1972	51.50	$5,326,988.02	70.00	22.02	0.3146	1.0000	$1,675,942.22	$76,099.83
1971	52.50	$6,580,173.12	70.00	21.28	0.3040	1.0000	$2,000,185.81	$94,002.47
1970	53.50	$9,263,720.17	70.00	20.54	0.2935	1.0000	$2,718,528.96	$132,338.86
1969	54.50	$7,053,890.36	70.00	19.81	0.2831	1.0000	$1,996,679.60	$100,769.86
1968	55.50	$6,494,654.32	70.00	19.10	0.2729	1.0000	$1,772,128.76	$92,780.78
1967	56.50	$5,149,879.17	70.00	18.39	0.2627	1.0000	$1,353,097.29	$73,569.70
1966	57.50	$3,518,216.93	70.00	17.70	0.2528	1.0000	$889,512.77	$50,260.24
1965	58.50	$3,847,320.65	70.00	17.01	0.2430	1.0000	$934,826.72	$54,961.72
1964	59.50	$4,506,126.97	70.00	16.33	0.2334	1.0000	$1,051,520.08	$64,373.24
1963	60.50	$2,452,755.44	70.00	15.67	0.2239	1.0000	$549,074.57	$35,039.36
1962	61.50	$1,964,920.70	70.00	15.02	0.2145	1.0000	$421,483.98	$28,070.30
1961	62.50	$2,363,765.72	70.00	14.38	0.2054	1.0000	$485,567.77	$33,768.08
1960	63.50	$1,549,498.96	70.00	13.76	0.1965	1.0000	$304,480.15	$22,135.70

Generation Arrangement Report

PECO Elect 366 Composite 2024

Account: PECO Electric 3660 PA
Dispersion: 70.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1959	64.50	$1,589,971.08	70.00	13.16	0.1880	1.0000	$298,837.14	$22,713.87
1958	65.50	$840,553.73	70.00	12.57	0.1796	1.0000	$150,950.08	$12,007.91
1957	66.50	$1,642,322.73	70.00	12.02	0.1717	1.0000	$281,933.27	$23,461.75
1956	67.50	$2,885,957.00	70.00	11.48	0.1640	1.0000	$473,424.81	$41,227.96
1955	68.50	$1,084,651.09	70.00	10.97	0.1567	1.0000	$169,966.28	$15,495.02
1954	69.50	$1,334,545.57	70.00	10.48	0.1498	1.0000	$199,855.45	$19,064.94
1953	70.50	$974,896.22	70.00	10.02	0.1431	1.0000	$139,483.64	$13,927.09
1952	71.50	$769,994.44	70.00	9.57	0.1368	1.0000	$105,315.58	$10,999.92
1951	72.50	$2,291,655.58	70.00	9.15	0.1307	1.0000	$299,590.60	$32,737.94
1950	73.50	$2,031,910.22	70.00	8.75	0.1250	1.0000	$253,995.40	$29,027.29
1949	74.50	$1,619,021.89	70.00	8.37	0.1195	1.0000	$193,520.72	$23,128.88
1948	75.50	$1,635,757.42	70.00	8.00	0.1143	1.0000	$186,976.78	$23,367.96
1947	76.50	$2,220,459.62	70.00	7.65	0.1093	1.0000	$242,668.08	$31,720.85
1946	77.50	$153,453.84	70.00	7.32	0.1045	1.0000	$16,038.97	$2,192.20
1945	78.50	$129,685.95	70.00	6.99	0.0999	1.0000	$12,950.71	$1,852.66
1944	79.50	$103,277.32	70.00	6.68	0.0955	1.0000	$9,861.02	$1,475.39
1943	80.50	$52,969.55	70.00	6.38	0.0911	1.0000	$4,824.91	$756.71
1942	81.50	$1,424,575.61	70.00	6.08	0.0868	1.0000	$123,712.18	$20,351.08
1941	82.50	$411,154.22	70.00	5.80	0.0828	1.0000	$34,042.75	$5,873.63
1940	83.50	$48,471.88	70.00	5.51	0.0787	1.0000	$3,815.06	$692.46
1939	84.50	$50,806.85	70.00	5.24	0.0749	1.0000	$3,804.04	$725.81
1938	85.50	$56,822.86	70.00	4.96	0.0709	1.0000	$4,027.47	$811.76
1937	86.50	$53,002.07	70.00	4.71	0.0672	1.0000	$3,562.89	$757.17
1936	87.50	$96,796.92	70.00	4.43	0.0633	1.0000	$6,126.67	$1,382.81
1935	88.50	$135,151.17	70.00	4.16	0.0595	1.0000	$8,036.08	$1,930.73
1934	89.50	$769,041.13	70.00	3.91	0.0559	1.0000	$42,958.54	$10,986.30
1933	90.50	$707,291.86	70.00	3.64	0.0521	1.0000	$36,822.82	$10,104.17
1932	91.50	$639,374.40	70.00	3.40	0.0486	1.0000	$31,098.37	$9,133.92
1931	92.50	$885,492.79	70.00	3.14	0.0449	1.0000	$39,748.03	$12,649.90
1930	93.50	$656,758.47	70.00	2.92	0.0417	1.0000	$27,399.07	$9,382.26
1929	94.50	$311,769.96	70.00	2.66	0.0381	1.0000	$11,863.13	$4,453.86
1928	95.50	$1,474,001.38	70.00	2.42	0.0345	1.0000	$50,871.52	$21,057.16

Generation Arrangement Report

PECO Elect 366 Composite 2024

Account: PECO Electric 3660 PA
Dispersion: 70.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1927	96.50	$1,811,135.41	70.00	2.20	0.0314	1.0000	$56,934.47	$25,873.36
1926	97.50	$942,371.68	70.00	1.96	0.0279	1.0000	$26,327.72	$13,462.45
1925	98.50	$1,080,224.52	70.00	1.77	0.0253	1.0000	$27,275.76	$15,431.78
1924	99.50	$1,007,842.76	70.00	1.53	0.0218	1.0000	$21,957.14	$14,397.75
1923	100.50	$450,592.47	70.00	1.38	0.0197	1.0000	$8,894.01	$6,437.04
1922	101.50	$214,429.81	70.00	1.16	0.0166	1.0000	$3,554.31	$3,063.28
1921	102.50	$192,870.11	70.00	0.94	0.0134	1.0000	$2,585.87	$2,755.29
1920	103.50	$151,062.11	70.00	0.81	0.0116	1.0000	$1,756.88	$2,158.03
1919	104.50	$246,656.92	70.00	0.60	0.0086	1.0000	$2,114.23	$3,523.67
1918	105.50	$59,370.39	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1917	106.50	$93,123.52	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1916	107.50	$93,745.74	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1915	108.50	$12,969.22	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1914	109.50	$93,252.16	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1913	110.50	$212,069.86	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1912	111.50	$89,938.06	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1911	112.50	$307,250.89	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1910	113.50	$54,752.51	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1909	114.50	$36,799.58	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1908	115.50	$97,656.94	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1907	116.50	$66,990.54	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1906	117.50	$54,913.30	70.00	0.00	0.0000	0.0000	$0.00	$0.00
1905	118.50	$1,775,544.86	70.00	0.00	0.0000	0.0000	$0.00	$0.00
		$765,407,398.43	70.00	53.51	0.7614	1.0000	$582,784,349.86	$10,890,843.16

Remaining Life Depreciation Accrual

Account: PECO Electric 3660 PA
Scenario: PECO Elect 366 Composite 2024
Dispersion: 70.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$765,407,398.43	53.51	$10,884,765.87	1.422088%	1.868760%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($6,815,166.77)	0.50	($48,679.76)	0.714286%	
Total:	$765,407,398.43 *		$10,836,086.11	1.415728%	1.860403%
Average:	$761,999,815.05		$10,836,086.11	1.422059%	1.871351%
Grand Total:	$765,407,398.43 *		$10,836,086.11	1.415728%	1.860403%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elect 367 Composite 2024

Account: PECO Electric 3670 PA
Dispersion: 54.00 - S0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$152,255,652.98	54.00	53.50	0.9908	1.0000	$150,859,742.68	$2,819,549.13
2022	1.50	$145,485,511.12	54.00	52.53	0.9729	1.0000	$141,535,717.34	$2,694,176.13
2021	2.50	$151,046,021.64	54.00	51.58	0.9553	1.0000	$144,288,173.28	$2,797,148.55
2020	3.50	$87,295,938.53	54.00	50.66	0.9381	1.0000	$81,889,660.90	$1,616,591.45
2019	4.50	$93,430,462.17	54.00	49.74	0.9212	1.0000	$86,065,241.48	$1,730,193.74
2018	5.50	$76,399,098.48	54.00	48.85	0.9046	1.0000	$69,109,825.24	$1,414,798.12
2017	6.50	$61,937,082.80	54.00	47.97	0.8883	1.0000	$55,019,474.94	$1,146,983.01
2016	7.50	$70,778,676.04	54.00	47.11	0.8723	1.0000	$61,742,034.70	$1,310,716.22
2015	8.50	$55,308,035.86	54.00	46.26	0.8566	1.0000	$47,378,955.86	$1,024,222.89
2014	9.50	$44,856,235.89	54.00	45.43	0.8412	1.0000	$37,734,148.31	$830,671.04
2013	10.50	$44,005,855.24	54.00	44.61	0.8261	1.0000	$36,355,066.45	$814,923.25
2012	11.50	$35,773,881.61	54.00	43.81	0.8113	1.0000	$29,023,080.28	$662,479.29
2011	12.50	$52,220,425.56	54.00	43.02	0.7967	1.0000	$41,604,268.34	$967,044.92
2010	13.50	$34,738,886.90	54.00	42.25	0.7824	1.0000	$27,179,049.92	$643,312.72
2009	14.50	$55,654,489.68	54.00	41.49	0.7683	1.0000	$42,759,761.12	$1,030,638.70
2008	15.50	$44,561,611.20	54.00	40.74	0.7545	1.0000	$33,620,797.26	$825,215.02
2007	16.50	$54,010,151.82	54.00	40.01	0.7409	1.0000	$40,015,633.22	$1,000,188.00
2006	17.50	$41,940,877.43	54.00	39.29	0.7276	1.0000	$30,515,790.62	$776,682.92
2005	18.50	$50,626,149.68	54.00	38.58	0.7145	1.0000	$36,171,255.00	$937,521.29
2004	19.50	$6,752,137.73	54.00	37.89	0.7016	1.0000	$4,737,257.15	$125,039.59
2003	20.50	$23,634,723.97	54.00	37.20	0.6889	1.0000	$16,282,523.49	$437,680.07
2002	21.50	$23,666,373.18	54.00	36.53	0.6765	1.0000	$16,009,704.18	$438,266.17
2001	22.50	$37,116,666.06	54.00	35.87	0.6642	1.0000	$24,653,936.88	$687,345.67
2000	23.50	$7,586,545.78	54.00	35.22	0.6522	1.0000	$4,947,760.42	$140,491.59
1999	24.50	$9,358,651.37	54.00	34.58	0.6404	1.0000	$5,993,085.22	$173,308.36
1998	25.50	$11,802,056.40	54.00	33.95	0.6287	1.0000	$7,420,332.44	$218,556.60
1997	26.50	$14,723,571.28	54.00	33.33	0.6173	1.0000	$9,088,452.14	$272,658.73
1996	27.50	$15,957,954.18	54.00	32.72	0.6060	1.0000	$9,670,568.06	$295,517.67
1995	28.50	$8,926,976.23	54.00	32.12	0.5949	1.0000	$5,310,626.81	$165,314.37
1994	29.50	$10,152,539.72	54.00	31.53	0.5840	1.0000	$5,928,805.68	$188,009.99
1993	30.50	$18,282,883.83	54.00	30.96	0.5732	1.0000	$10,480,614.74	$338,571.92
1992	31.50	$14,153,805.13	54.00	30.38	0.5627	1.0000	$7,963,759.21	$262,107.50

Generation Arrangement Report

PECO Elect 367 Composite 2024

Account: PECO Electric 3670 PA
Dispersion: 54.00 - S0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$14,817,936.85	54.00	29.82	0.5522	1.0000	$8,182,956.57	$274,406.24
1990	33.50	$24,841,330.35	54.00	29.27	0.5420	1.0000	$13,462,999.21	$460,024.64
1989	34.50	$21,176,352.98	54.00	28.72	0.5318	1.0000	$11,262,299.43	$392,154.68
1988	35.50	$19,200,596.29	54.00	28.18	0.5219	1.0000	$10,019,861.40	$355,566.60
1987	36.50	$15,214,487.37	54.00	27.65	0.5120	1.0000	$7,790,049.28	$281,749.77
1986	37.50	$12,555,089.65	54.00	27.13	0.5023	1.0000	$6,307,014.12	$232,501.66
1985	38.50	$11,681,113.35	54.00	26.61	0.4928	1.0000	$5,756,332.62	$216,316.91
1984	39.50	$10,144,131.80	54.00	26.10	0.4834	1.0000	$4,903,291.16	$187,854.29
1983	40.50	$10,262,884.30	54.00	25.60	0.4741	1.0000	$4,865,282.15	$190,053.41
1982	41.50	$6,538,485.00	54.00	25.10	0.4649	1.0000	$3,039,645.41	$121,083.06
1981	42.50	$7,770,680.98	54.00	24.61	0.4558	1.0000	$3,542,084.19	$143,901.50
1980	43.50	$6,667,584.40	54.00	24.13	0.4469	1.0000	$2,979,662.75	$123,473.79
1979	44.50	$7,219,375.44	54.00	23.66	0.4381	1.0000	$3,162,658.34	$133,692.14
1978	45.50	$5,985,843.47	54.00	23.19	0.4294	1.0000	$2,570,105.92	$110,848.95
1977	46.50	$5,685,353.63	54.00	22.72	0.4208	1.0000	$2,392,179.16	$105,284.33
1976	47.50	$5,102,117.35	54.00	22.26	0.4123	1.0000	$2,103,380.47	$94,483.65
1975	48.50	$3,981,294.67	54.00	21.81	0.4039	1.0000	$1,607,873.03	$73,727.68
1974	49.50	$6,443,696.86	54.00	21.36	0.3956	1.0000	$2,548,867.20	$119,327.72
1973	50.50	$5,454,221.57	54.00	20.92	0.3874	1.0000	$2,112,696.00	$101,004.10
1972	51.50	$4,795,149.63	54.00	20.48	0.3792	1.0000	$1,818,515.13	$88,799.07
1971	52.50	$4,797,281.80	54.00	20.05	0.3712	1.0000	$1,780,840.97	$88,838.55
1970	53.50	$3,988,729.09	54.00	19.62	0.3633	1.0000	$1,449,032.42	$73,865.35
1969	54.50	$3,754,568.13	54.00	19.19	0.3554	1.0000	$1,334,516.46	$69,529.04
1968	55.50	$2,505,416.98	54.00	18.77	0.3477	1.0000	$871,057.56	$46,396.61
1967	56.50	$2,791,832.59	54.00	18.36	0.3400	1.0000	$949,186.29	$51,700.60
1966	57.50	$2,501,027.91	54.00	17.95	0.3324	1.0000	$831,268.37	$46,315.33
1965	58.50	$1,803,615.19	54.00	17.54	0.3248	1.0000	$585,873.52	$33,400.28
1964	59.50	$5,290,757.82	54.00	17.14	0.3174	1.0000	$1,679,145.96	$97,977.00
1963	60.50	$1,107,323.12	54.00	16.74	0.3100	1.0000	$343,253.90	$20,505.98
1962	61.50	$1,199,530.68	54.00	16.34	0.3027	1.0000	$363,051.41	$22,213.53
1961	62.50	$1,400,464.00	54.00	15.95	0.2954	1.0000	$413,716.22	$25,934.52
1960	63.50	$879,939.23	54.00	15.56	0.2882	1.0000	$253,616.34	$16,295.17

Generation Arrangement Report

PECO Elect 367 Composite 2024

Account: PECO Electric 3670 PA
Dispersion: 54.00 - S0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1959	64.50	$887,348.72	54.00	15.18	0.2811	1.0000	$249,415.63	$16,432.38
1958	65.50	$430,402.46	54.00	14.80	0.2740	1.0000	$117,936.05	$7,970.42
1957	66.50	$1,236,776.93	54.00	14.42	0.2670	1.0000	$330,222.10	$22,903.28
1956	67.50	$1,697,241.32	54.00	14.04	0.2600	1.0000	$441,358.70	$31,430.39
1955	68.50	$718,080.54	54.00	13.67	0.2532	1.0000	$181,783.19	$13,297.79
1954	69.50	$65,377.68	54.00	13.30	0.2463	1.0000	$16,103.16	$1,210.70
1953	70.50	$474,660.19	54.00	12.93	0.2395	1.0000	$113,690.17	$8,790.00
1952	71.50	$326,506.29	54.00	12.57	0.2327	1.0000	$75,993.44	$6,046.41
1951	72.50	$984,824.80	54.00	12.21	0.2260	1.0000	$222,616.77	$18,237.50
1950	73.50	$782,228.81	54.00	11.85	0.2194	1.0000	$171,611.90	$14,485.72
1949	74.50	$1,033,482.25	54.00	11.49	0.2128	1.0000	$219,898.33	$19,138.56
1948	75.50	$397,741.69	54.00	11.14	0.2062	1.0000	$82,017.62	$7,365.59
1947	76.50	$53,416.54	54.00	10.78	0.1997	1.0000	$10,667.02	$989.20
1946	77.50	$36,636.05	54.00	10.43	0.1932	1.0000	$7,078.34	$678.45
1945	78.50	$38,438.51	54.00	10.08	0.1867	1.0000	$7,176.53	$711.82
1944	79.50	$22,649.57	54.00	9.73	0.1803	1.0000	$4,083.20	$419.44
1941	82.50	$88,611.90	54.00	8.70	0.1612	1.0000	$14,283.87	$1,640.96
1940	83.50	$4,087.47	54.00	8.36	0.1549	1.0000	$633.11	$75.69
1939	84.50	$20,175.36	54.00	8.02	0.1486	1.0000	$2,997.19	$373.62
1938	85.50	$19,324.57	54.00	7.68	0.1423	1.0000	$2,749.49	$357.86
1937	86.50	$22,400.79	54.00	7.35	0.1360	1.0000	$3,047.28	$414.83
1936	87.50	$2,532.35	54.00	7.01	0.1298	1.0000	$328.72	$46.90
1935	88.50	$6,171.03	54.00	6.67	0.1236	1.0000	$762.73	$114.28
1934	89.50	$27,807.18	54.00	6.34	0.1174	1.0000	$3,264.88	$514.95
1933	90.50	$32,581.42	54.00	6.01	0.1112	1.0000	$3,624.49	$603.36
1932	91.50	$34,013.60	54.00	5.67	0.1050	1.0000	$3,570.52	$629.88
1931	92.50	$48,655.84	54.00	5.33	0.0988	1.0000	$4,806.29	$901.03
1930	93.50	$60,792.97	54.00	5.00	0.0926	1.0000	$5,629.25	$1,125.80
1929	94.50	$41,892.30	54.00	4.67	0.0864	1.0000	$3,620.30	$775.78
1928	95.50	$40,359.80	54.00	4.33	0.0802	1.0000	$3,238.72	$747.40
1927	96.50	$38,182.12	54.00	4.00	0.0741	1.0000	$2,828.53	$707.08
1926	97.50	$32,739.54	54.00	3.67	0.0679	1.0000	$2,224.08	$606.29

Generation Arrangement Report

PECO Elect 367 Composite 2024

Account: PECO Electric 3670 PA
Dispersion: 54.00 - S0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1925	98.50	$29,623.98	54.00	3.32	0.0616	1.0000	$1,823.72	$548.59
1924	99.50	$509.62	54.00	2.99	0.0553	1.0000	$28.18	$9.44
		$1,801,734,416.16	54.00	43.01	0.7964	1.0000	$1,434,948,529.81	$33,365,452.15

Remaining Life Depreciation Accrual

Account: PECO Electric 3670 PA
Scenario: PECO Elect 367 Composite 2024
Dispersion: 54.00 - S0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,801,734,416.16	43.01	$37,070,683.76	2.057500%	2.325202%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($12,039,019.51)	0.50	($111,472.40)	0.925926%	
Total:	$1,801,734,416.16 *		$36,959,211.36	2.051313%	2.318210%
Average:	$1,795,714,906.41		$36,959,211.36	2.058189%	2.326996%
Grand Total:	$1,801,734,416.16 *		$36,959,211.36	2.051313%	2.318210%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3680 PA
Dispersion: 47.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$64,106,238.15	47.00	46.59	0.9912	1.0000	$63,544,034.27	$1,363,962.51
2022	1.50	$54,567,294.26	47.00	45.77	0.9738	1.0000	$53,136,726.08	$1,161,006.26
2021	2.50	$42,683,611.40	47.00	44.95	0.9564	1.0000	$40,823,788.13	$908,161.94
2020	3.50	$44,413,752.84	47.00	44.14	0.9392	1.0000	$41,712,643.86	$944,973.46
2019	4.50	$37,619,486.28	47.00	43.33	0.9220	1.0000	$34,685,846.05	$800,414.60
2018	5.50	$28,155,985.44	47.00	42.53	0.9050	1.0000	$25,481,159.75	$599,063.52
2017	6.50	$19,336,250.82	47.00	41.74	0.8881	1.0000	$17,171,757.43	$411,409.59
2016	7.50	$22,035,574.85	47.00	40.95	0.8712	1.0000	$19,198,382.05	$468,842.02
2015	8.50	$18,057,253.60	47.00	40.16	0.8545	1.0000	$15,430,288.97	$384,196.89
2014	9.50	$23,111,446.76	47.00	39.38	0.8379	1.0000	$19,365,331.26	$491,732.91
2013	10.50	$15,672,229.72	47.00	38.61	0.8214	1.0000	$12,873,317.41	$333,451.70
2012	11.50	$15,523,009.42	47.00	37.84	0.8050	1.0000	$12,496,212.20	$330,276.80
2011	12.50	$15,996,947.89	47.00	37.07	0.7887	1.0000	$12,616,947.84	$340,360.59
2010	13.50	$14,279,069.96	47.00	36.31	0.7725	1.0000	$11,031,008.06	$303,810.00
2009	14.50	$10,348,893.95	47.00	35.55	0.7565	1.0000	$7,828,461.61	$220,189.23
2008	15.50	$12,364,240.36	47.00	34.80	0.7405	1.0000	$9,155,689.84	$263,068.94
2007	16.50	$12,477,430.89	47.00	34.06	0.7247	1.0000	$9,041,833.02	$265,477.25
2006	17.50	$8,385,624.90	47.00	33.32	0.7089	1.0000	$5,944,830.64	$178,417.55
2005	18.50	$14,210,039.47	47.00	32.59	0.6933	1.0000	$9,852,238.24	$302,341.27
2004	19.50	$10,671,424.91	47.00	31.86	0.6779	1.0000	$7,233,657.08	$227,051.59
2003	20.50	$4,016,191.68	47.00	31.14	0.6625	1.0000	$2,660,693.34	$85,450.89
2002	21.50	$11,406,298.61	47.00	30.42	0.6473	1.0000	$7,383,147.98	$242,687.20
2001	22.50	$25,316,980.04	47.00	29.71	0.6322	1.0000	$16,006,159.18	$538,659.15
1999	24.50	$9,658,856.25	47.00	28.32	0.6026	1.0000	$5,820,034.78	$205,507.58
1998	25.50	$10,991,743.61	47.00	27.63	0.5880	1.0000	$6,462,729.21	$233,866.89
1997	26.50	$12,172,150.87	47.00	26.96	0.5735	1.0000	$6,981,072.03	$258,981.93
1996	27.50	$7,300,467.42	47.00	26.28	0.5592	1.0000	$4,082,667.61	$155,329.09
1995	28.50	$13,330,394.11	47.00	25.62	0.5451	1.0000	$7,267,044.53	$283,625.41
1994	29.50	$11,725,718.15	47.00	24.97	0.5312	1.0000	$6,229,213.94	$249,483.36
1993	30.50	$9,162,160.83	47.00	24.32	0.5175	1.0000	$4,741,592.59	$194,939.59
1992	31.50	$9,063,134.10	47.00	23.69	0.5040	1.0000	$4,567,708.32	$192,832.64
1991	32.50	$8,875,122.70	47.00	23.06	0.4906	1.0000	$4,354,569.45	$188,832.40

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3680 PA
Dispersion: 47.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1990	33.50	$14,991,555.32	47.00	22.44	0.4775	1.0000	$7,158,596.00	$318,969.26
1989	34.50	$17,748,578.85	47.00	21.83	0.4646	1.0000	$8,245,454.91	$377,629.34
1988	35.50	$12,781,448.18	47.00	21.24	0.4518	1.0000	$5,774,797.10	$271,945.71
1987	36.50	$11,084,450.65	47.00	20.65	0.4393	1.0000	$4,869,353.91	$235,839.38
1986	37.50	$10,627,476.68	47.00	20.07	0.4270	1.0000	$4,537,978.08	$226,116.53
1985	38.50	$10,105,770.54	47.00	19.50	0.4149	1.0000	$4,193,121.02	$215,016.39
1984	39.50	$7,052,766.74	47.00	18.94	0.4031	1.0000	$2,842,727.60	$150,058.87
1983	40.50	$4,341,903.95	47.00	18.40	0.3914	1.0000	$1,699,600.93	$92,380.94
1982	41.50	$4,754,143.78	47.00	17.86	0.3800	1.0000	$1,806,764.15	$101,152.00
1981	42.50	$3,920,404.97	47.00	17.34	0.3689	1.0000	$1,446,107.65	$83,412.87
1980	43.50	$3,358,191.68	47.00	16.82	0.3579	1.0000	$1,201,936.73	$71,450.89
1979	44.50	$3,702,359.35	47.00	16.32	0.3472	1.0000	$1,285,510.51	$78,773.60
1978	45.50	$4,144,298.79	47.00	15.83	0.3368	1.0000	$1,395,598.97	$88,176.57
1977	46.50	$2,585,674.74	47.00	15.35	0.3265	1.0000	$844,309.12	$55,014.36
1976	47.50	$1,409,602.87	47.00	14.88	0.3165	1.0000	$446,206.35	$29,991.55
1975	48.50	$2,085,110.83	47.00	14.42	0.3068	1.0000	$639,713.20	$44,364.06
1974	49.50	$4,791,959.71	47.00	13.97	0.2973	1.0000	$1,424,602.15	$101,956.59
1973	50.50	$4,807,177.03	47.00	13.54	0.2880	1.0000	$1,384,504.47	$102,280.36
1972	51.50	$3,031,418.93	47.00	13.11	0.2790	1.0000	$845,632.03	$64,498.28
1971	52.50	$2,821,512.48	47.00	12.70	0.2701	1.0000	$762,210.78	$60,032.18
1970	53.50	$4,924,347.40	47.00	12.29	0.2616	1.0000	$1,287,986.02	$104,773.35
1969	54.50	$7,188,512.98	47.00	11.90	0.2532	1.0000	$1,819,986.43	$152,947.08
1968	55.50	$4,854,289.39	47.00	11.52	0.2450	1.0000	$1,189,393.21	$103,282.75
1967	56.50	$2,271,050.38	47.00	11.14	0.2371	1.0000	$538,375.17	$48,320.22
1966	57.50	$1,135,012.50	47.00	10.78	0.2293	1.0000	$260,258.71	$24,149.20
1965	58.50	$645,616.24	47.00	10.42	0.2217	1.0000	$143,156.95	$13,736.52
1964	59.50	$576,151.79	47.00	10.08	0.2144	1.0000	$123,508.15	$12,258.55
1963	60.50	$717,355.67	47.00	9.74	0.2071	1.0000	$148,600.05	$15,262.89
1962	61.50	$487,230.40	47.00	9.40	0.2001	1.0000	$97,491.14	$10,366.60
1961	62.50	$520,189.48	47.00	9.08	0.1932	1.0000	$100,487.07	$11,067.86
1960	63.50	$647,488.24	47.00	8.76	0.1864	1.0000	$120,688.95	$13,776.35
1959	64.50	$490,335.23	47.00	8.45	0.1797	1.0000	$88,134.67	$10,432.66

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3680 PA
Dispersion: 47.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1958	65.50	$429,700.55	47.00	8.14	0.1732	1.0000	$74,430.37	$9,142.56
1957	66.50	$465,671.09	47.00	7.84	0.1668	1.0000	$77,669.85	$9,907.90
1956	67.50	$576,593.93	47.00	7.55	0.1605	1.0000	$92,563.15	$12,267.96
1955	68.50	$462,900.48	47.00	7.25	0.1543	1.0000	$71,432.60	$9,848.95
1954	69.50	$353,874.68	47.00	6.96	0.1482	1.0000	$52,435.22	$7,529.25
1953	70.50	$230,349.07	47.00	6.68	0.1421	1.0000	$32,741.88	$4,901.04
1952	71.50	$176,031.87	47.00	6.40	0.1362	1.0000	$23,977.16	$3,745.36
1951	72.50	$116,894.96	47.00	6.13	0.1304	1.0000	$15,239.54	$2,487.13
1950	73.50	$67,499.82	47.00	5.86	0.1246	1.0000	$8,413.55	$1,436.17
1949	74.50	$50,253.80	47.00	5.60	0.1192	1.0000	$5,989.62	$1,069.23
1948	75.50	$32,153.19	47.00	5.34	0.1137	1.0000	$3,656.26	$684.11
1947	76.50	$20,671.21	47.00	5.09	0.1084	1.0000	$2,240.32	$439.81
1946	77.50	$7,055.30	47.00	4.85	0.1032	1.0000	$728.02	$150.11
1945	78.50	$619.48	47.00	4.61	0.0981	1.0000	$60.79	$13.18
1942	81.50	$171.93	47.00	3.93	0.0836	1.0000	$14.38	$3.66
1941	82.50	$272.71	47.00	3.72	0.0792	1.0000	$21.59	$5.80
		$774,629,124.08	47.00	34.24	0.7286	1.0000	$564,365,193.23	$16,481,470.73

Remaining Life Depreciation Accrual

Account: PECO Electric 3680 PA
Scenario: PECO Electric Groups 2024
Dispersion: 47.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$774,629,124.08	34.24	$17,421,066.25	2.248956%	2.920356%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($9,114,853.66)	0.50	($96,966.53)	1.063830%	
Total:	$774,629,124.08 *		$17,324,099.72	2.236438%	2.904101%
Average:	$770,071,697.25		$17,324,099.72	2.249674%	2.926458%
Grand Total:	$774,629,124.08 *		$17,324,099.72	2.236438%	2.904101%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3691 PA
Dispersion: 53.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$9,067,154.79	53.00	52.50	0.9906	1.0000	$8,981,700.67	$171,078.39
2022	1.50	$6,702,428.58	53.00	51.50	0.9717	1.0000	$6,512,924.18	$126,460.92
2021	2.50	$7,553,846.61	53.00	50.50	0.9529	1.0000	$7,197,953.69	$142,525.41
2020	3.50	$7,431,728.56	53.00	49.50	0.9340	1.0000	$6,941,514.66	$140,221.29
2019	4.50	$6,655,004.09	53.00	48.51	0.9152	1.0000	$6,090,776.77	$125,566.11
2018	5.50	$6,584,150.73	53.00	47.51	0.8964	1.0000	$5,902,008.53	$124,229.26
2017	6.50	$6,217,284.47	53.00	46.51	0.8776	1.0000	$5,456,240.24	$117,307.25
2016	7.50	$6,213,580.36	53.00	45.52	0.8588	1.0000	$5,336,261.26	$117,237.37
2015	8.50	$4,305,588.00	53.00	44.52	0.8400	1.0000	$3,616,812.60	$81,237.51
2014	9.50	$4,550,535.46	53.00	43.53	0.8213	1.0000	$3,737,247.68	$85,859.16
2013	10.50	$3,843,933.82	53.00	42.54	0.8026	1.0000	$3,084,949.21	$72,527.05
2012	11.50	$3,739,094.91	53.00	41.54	0.7839	1.0000	$2,930,915.97	$70,548.96
2011	12.50	$3,949,941.80	53.00	40.56	0.7652	1.0000	$3,022,494.72	$74,527.20
2010	13.50	$4,362,870.20	53.00	39.57	0.7466	1.0000	$3,257,255.22	$82,318.31
2009	14.50	$4,786,612.96	53.00	38.58	0.7280	1.0000	$3,484,722.15	$90,313.45
2008	15.50	$4,813,707.50	53.00	37.60	0.7095	1.0000	$3,415,313.31	$90,824.67
2007	16.50	$4,110,837.75	53.00	36.63	0.6910	1.0000	$2,840,776.84	$77,562.98
2006	17.50	$5,281,936.43	53.00	35.65	0.6727	1.0000	$3,552,936.92	$99,659.18
2005	18.50	$5,942,543.51	53.00	34.68	0.6544	1.0000	$3,888,513.34	$112,123.46
2004	19.50	$5,601,123.10	53.00	33.72	0.6361	1.0000	$3,563,056.83	$105,681.57
2003	20.50	$4,191,585.75	53.00	32.75	0.6180	1.0000	$2,590,442.12	$79,086.52
2002	21.50	$7,556,736.70	53.00	31.80	0.6000	1.0000	$4,534,050.07	$142,579.94
2001	22.50	$8,451,151.24	53.00	30.85	0.5821	1.0000	$4,919,678.34	$159,455.68
2000	23.50	$2,082,538.21	53.00	29.91	0.5644	1.0000	$1,175,336.03	$39,293.17
1999	24.50	$3,001,444.82	53.00	28.98	0.5468	1.0000	$1,641,094.16	$56,631.03
1998	25.50	$2,687,663.07	53.00	28.05	0.5293	1.0000	$1,422,603.30	$50,710.62
1997	26.50	$3,152,059.45	53.00	27.14	0.5120	1.0000	$1,613,916.89	$59,472.82
1996	27.50	$1,390,272.86	53.00	26.23	0.4949	1.0000	$688,061.78	$26,231.56
1995	28.50	$3,094,179.93	53.00	25.33	0.4780	1.0000	$1,479,003.39	$58,380.75
1994	29.50	$1,531,640.58	53.00	24.45	0.4613	1.0000	$706,508.29	$28,898.88
1993	30.50	$1,660,025.64	53.00	23.57	0.4448	1.0000	$738,331.28	$31,321.24
1992	31.50	$1,490,982.56	53.00	22.71	0.4285	1.0000	$638,957.13	$28,131.75

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3691 PA
Dispersion: 53.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$1,478,771.19	53.00	21.86	0.4125	1.0000	$610,017.55	$27,901.34
1990	33.50	$1,892,572.40	53.00	21.03	0.3967	1.0000	$750,837.80	$35,708.91
1989	34.50	$2,288,122.96	53.00	20.20	0.3812	1.0000	$872,212.74	$43,172.13
1988	35.50	$1,972,409.94	53.00	19.39	0.3659	1.0000	$721,735.44	$37,215.28
1987	36.50	$1,869,084.48	53.00	18.60	0.3509	1.0000	$655,854.17	$35,265.74
1986	37.50	$1,734,521.79	53.00	17.82	0.3361	1.0000	$583,049.76	$32,726.83
1985	38.50	$1,488,755.57	53.00	17.05	0.3217	1.0000	$478,878.61	$28,089.73
1984	39.50	$1,583,614.34	53.00	16.29	0.3074	1.0000	$486,880.71	$29,879.52
1983	40.50	$1,296,209.83	53.00	15.56	0.2936	1.0000	$380,524.68	$24,456.79
1982	41.50	$1,326,368.83	53.00	14.83	0.2799	1.0000	$371,244.64	$25,025.83
1981	42.50	$959,930.29	53.00	14.12	0.2665	1.0000	$255,803.30	$18,111.89
1980	43.50	$1,450,602.99	53.00	13.43	0.2533	1.0000	$367,451.02	$27,369.87
1979	44.50	$1,222,017.01	53.00	12.74	0.2404	1.0000	$293,743.20	$23,056.92
1978	45.50	$1,220,325.27	53.00	12.07	0.2277	1.0000	$277,854.40	$23,025.01
1977	46.50	$1,199,641.07	53.00	11.41	0.2153	1.0000	$258,277.40	$22,634.74
1976	47.50	$1,053,876.88	53.00	10.77	0.2033	1.0000	$214,213.64	$19,884.47
1975	48.50	$1,066,384.98	53.00	10.16	0.1917	1.0000	$204,388.31	$20,120.47
1974	49.50	$1,081,779.95	53.00	9.58	0.1807	1.0000	$195,465.23	$20,410.94
1973	50.50	$964,767.48	53.00	9.02	0.1702	1.0000	$164,179.55	$18,203.16
1972	51.50	$828,949.94	53.00	8.49	0.1602	1.0000	$132,828.57	$15,640.56
1971	52.50	$735,574.19	53.00	8.00	0.1509	1.0000	$110,985.34	$13,878.76
1970	53.50	$900,349.23	53.00	7.53	0.1421	1.0000	$127,944.15	$16,987.72
1969	54.50	$957,433.09	53.00	7.10	0.1339	1.0000	$128,179.89	$18,064.78
1968	55.50	$695,026.43	53.00	6.69	0.1262	1.0000	$87,695.41	$13,113.71
1967	56.50	$626,957.50	53.00	6.30	0.1190	1.0000	$74,579.90	$11,829.39
1966	57.50	$653,637.95	53.00	5.94	0.1121	1.0000	$73,288.24	$12,332.79
1965	58.50	$462,077.56	53.00	5.60	0.1057	1.0000	$48,830.86	$8,718.44
1964	59.50	$663,566.16	53.00	5.28	0.0996	1.0000	$66,061.61	$12,520.12
1963	60.50	$569,140.16	53.00	4.97	0.0937	1.0000	$53,334.50	$10,738.49
1962	61.50	$467,692.24	53.00	4.67	0.0881	1.0000	$41,203.18	$8,824.38
1961	62.50	$412,928.43	53.00	4.38	0.0827	1.0000	$34,144.26	$7,791.10
1960	63.50	$364,910.88	53.00	4.10	0.0774	1.0000	$28,257.27	$6,885.11

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3691 PA
Dispersion: 53.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1959	64.50	$416,789.76	53.00	3.83	0.0723	1.0000	$30,145.06	$7,863.96
1958	65.50	$415,090.65	53.00	3.57	0.0673	1.0000	$27,953.18	$7,831.90
1957	66.50	$370,349.92	53.00	3.29	0.0622	1.0000	$23,020.44	$6,987.73
1956	67.50	$398,492.94	53.00	3.03	0.0572	1.0000	$22,802.27	$7,518.73
1955	68.50	$261,149.83	53.00	2.78	0.0524	1.0000	$13,674.15	$4,927.36
1954	69.50	$3,329.09	53.00	2.52	0.0476	1.0000	$158.43	$62.81
1953	70.50	$16,629.57	53.00	2.28	0.0429	1.0000	$713.91	$313.77
1952	71.50	$50,640.65	53.00	2.04	0.0384	1.0000	$1,945.14	$955.48
		$189,424,657.86	53.00	34.76	0.6558	1.0000	$124,232,715.48	$3,574,050.15

Remaining Life Depreciation Accrual

Account: PECO Electric 3691 PA
Scenario: PECO Electric Groups 2024
Dispersion: 53.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$189,424,657.86	34.76	$3,533,570.23	1.865423%	2.876899%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,965,049.68)	0.50	($18,538.20)	0.943396%	
Total:	$189,424,657.86 *		$3,515,032.03	1.855636%	2.861806%
Average:	$188,442,133.02		$3,515,032.03	1.865311%	2.884883%
Grand Total:	$189,424,657.86 *		$3,515,032.03	1.855636%	2.861806%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3692 PA
Dispersion: 55.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$2,041,298.22	55.00	54.51	0.9910	1.0000	$2,023,014.41	$37,114.51
2022	1.50	$3,049,568.79	55.00	53.52	0.9732	1.0000	$2,967,776.81	$55,446.71
2021	2.50	$3,790,099.04	55.00	52.54	0.9553	1.0000	$3,620,841.05	$68,910.89
2020	3.50	$1,450,375.57	55.00	51.57	0.9376	1.0000	$1,359,818.96	$26,370.46
2019	4.50	$2,241,375.31	55.00	50.59	0.9198	1.0000	$2,061,704.33	$40,752.28
2018	5.50	$3,232,605.03	55.00	49.62	0.9022	1.0000	$2,916,345.82	$58,774.64
2017	6.50	$1,851,812.69	55.00	48.65	0.8845	1.0000	$1,638,016.26	$33,669.32
2016	7.50	$2,822,862.22	55.00	47.68	0.8670	1.0000	$2,447,409.97	$51,324.77
2015	8.50	$1,501,171.20	55.00	46.72	0.8495	1.0000	$1,275,291.33	$27,294.02
2014	9.50	$1,735,099.82	55.00	45.77	0.8321	1.0000	$1,443,839.86	$31,547.27
2013	10.50	$1,432,546.49	55.00	44.82	0.8148	1.0000	$1,167,269.61	$26,046.30
2012	11.50	$1,117,795.15	55.00	43.87	0.7976	1.0000	$891,540.93	$20,323.55
2011	12.50	$6,134,038.71	55.00	42.92	0.7804	1.0000	$4,787,288.17	$111,527.98
2010	13.50	$1,818,243.77	55.00	41.99	0.7634	1.0000	$1,388,050.61	$33,058.98
2009	14.50	$3,796,217.95	55.00	41.06	0.7465	1.0000	$2,833,823.66	$69,022.14
2008	15.50	$4,826,865.70	55.00	40.13	0.7297	1.0000	$3,521,979.18	$87,761.19
2007	16.50	$4,966,925.88	55.00	39.21	0.7129	1.0000	$3,541,124.77	$90,307.74
2006	17.50	$6,511,821.96	55.00	38.30	0.6963	1.0000	$4,534,454.63	$118,396.76
2005	18.50	$11,635,220.85	55.00	37.39	0.6799	1.0000	$7,910,439.59	$211,549.47
2004	19.50	$1,418,515.06	55.00	36.50	0.6635	1.0000	$941,249.42	$25,791.18
2003	20.50	$8,135,680.50	55.00	35.60	0.6473	1.0000	$5,266,527.56	$147,921.46
2002	21.50	$11,347,136.74	55.00	34.72	0.6313	1.0000	$7,163,020.39	$206,311.58
2001	22.50	$11,321,036.17	55.00	33.84	0.6153	1.0000	$6,966,137.08	$205,837.02
2000	23.50	$1,214,784.83	55.00	32.97	0.5995	1.0000	$728,300.61	$22,087.00
1999	24.50	$9,387,665.82	55.00	32.11	0.5839	1.0000	$5,481,335.15	$170,684.83
1998	25.50	$5,666,018.59	55.00	31.26	0.5684	1.0000	$3,220,751.66	$103,018.52
1997	26.50	$9,480,532.66	55.00	30.42	0.5531	1.0000	$5,243,709.19	$172,373.32
1996	27.50	$3,952,159.25	55.00	29.59	0.5379	1.0000	$2,125,971.43	$71,857.44
1995	28.50	$9,631,779.96	55.00	28.76	0.5229	1.0000	$5,036,596.16	$175,123.27
1994	29.50	$5,392,678.51	55.00	27.94	0.5081	1.0000	$2,739,828.43	$98,048.70
1993	30.50	$10,175,363.74	55.00	27.14	0.4934	1.0000	$5,020,756.55	$185,006.61
1992	31.50	$8,417,039.43	55.00	26.34	0.4789	1.0000	$4,031,139.68	$153,037.08

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3692 PA
Dispersion: 55.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$7,562,218.75	55.00	25.55	0.4646	1.0000	$3,513,420.41	$137,494.89
1990	33.50	$10,364,590.67	55.00	24.78	0.4505	1.0000	$4,668,811.15	$188,447.10
1989	34.50	$10,660,527.98	55.00	24.01	0.4365	1.0000	$4,653,207.13	$193,827.78
1988	35.50	$11,333,403.26	55.00	23.25	0.4227	1.0000	$4,790,699.58	$206,061.88
1987	36.50	$11,220,804.33	55.00	22.50	0.4092	1.0000	$4,591,255.82	$204,014.62
1986	37.50	$9,694,328.79	55.00	21.77	0.3958	1.0000	$3,836,988.72	$176,260.52
1985	38.50	$7,910,064.93	55.00	21.04	0.3826	1.0000	$3,026,580.45	$143,819.36
1984	39.50	$7,530,644.26	55.00	20.33	0.3697	1.0000	$2,783,773.18	$136,920.80
1983	40.50	$5,723,028.12	55.00	19.63	0.3569	1.0000	$2,042,573.86	$104,055.06
1982	41.50	$2,962,981.33	55.00	18.94	0.3444	1.0000	$1,020,549.74	$53,872.39
1981	42.50	$4,926,244.81	55.00	18.27	0.3322	1.0000	$1,636,291.32	$89,568.09
1980	43.50	$4,968,840.86	55.00	17.61	0.3201	1.0000	$1,590,632.59	$90,342.56
1979	44.50	$4,440,341.73	55.00	16.96	0.3083	1.0000	$1,369,089.77	$80,733.49
1978	45.50	$4,230,810.21	55.00	16.32	0.2968	1.0000	$1,255,680.67	$76,923.82
1977	46.50	$2,509,360.18	55.00	15.70	0.2855	1.0000	$716,483.15	$45,624.73
1976	47.50	$2,046,787.48	55.00	15.10	0.2746	1.0000	$562,047.71	$37,214.32
1975	48.50	$1,391,307.95	55.00	14.51	0.2639	1.0000	$367,175.22	$25,296.51
1974	49.50	$1,470,779.44	55.00	13.94	0.2535	1.0000	$372,847.59	$26,741.44
1973	50.50	$1,574,101.49	55.00	13.39	0.2434	1.0000	$383,127.74	$28,620.03
1972	51.50	$623,898.09	55.00	12.85	0.2336	1.0000	$145,735.05	$11,343.60
1971	52.50	$442,258.64	55.00	12.33	0.2241	1.0000	$99,128.85	$8,041.07
1970	53.50	$298,958.65	55.00	11.82	0.2150	1.0000	$64,267.87	$5,435.61
1969	54.50	$269,045.44	55.00	11.34	0.2061	1.0000	$55,453.75	$4,891.74
1968	55.50	$271,931.32	55.00	10.87	0.1976	1.0000	$53,725.38	$4,944.21
1967	56.50	$205,658.60	55.00	10.41	0.1893	1.0000	$38,939.50	$3,739.25
1966	57.50	$245,479.69	55.00	9.98	0.1814	1.0000	$44,535.98	$4,463.27
1965	58.50	$232,044.92	55.00	9.56	0.1738	1.0000	$40,338.40	$4,219.00
1964	59.50	$147,675.54	55.00	9.16	0.1665	1.0000	$24,593.16	$2,685.01
1963	60.50	$104,839.44	55.00	8.77	0.1595	1.0000	$16,724.41	$1,906.17
1962	61.50	$157,573.08	55.00	8.40	0.1528	1.0000	$24,077.76	$2,864.97
1961	62.50	$179,798.51	55.00	8.05	0.1464	1.0000	$26,314.62	$3,269.06
1960	63.50	$163,745.41	55.00	7.71	0.1401	1.0000	$22,946.34	$2,977.19

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3692 PA
Dispersion: 55.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1959	64.50	$93,933.50	55.00	7.38	0.1342	1.0000	$12,603.50	$1,707.88
1958	65.50	$64,131.04	55.00	7.06	0.1284	1.0000	$8,237.11	$1,166.02
1957	66.50	$74,791.29	55.00	6.76	0.1229	1.0000	$9,194.12	$1,359.84
1956	67.50	$86,605.80	55.00	6.47	0.1176	1.0000	$10,185.76	$1,574.65
1955	68.50	$62,728.92	55.00	6.19	0.1125	1.0000	$7,055.89	$1,140.53
1954	69.50	$87,605.25	55.00	5.90	0.1073	1.0000	$9,402.09	$1,592.82
1953	70.50	$100,033.13	55.00	5.63	0.1024	1.0000	$10,243.08	$1,818.78
1952	71.50	$40,617.21	55.00	5.37	0.0976	1.0000	$3,963.15	$738.49
1949	74.50	$38,281.78	55.00	4.58	0.0834	1.0000	$3,190.91	$696.03
1948	75.50	$26,558.19	55.00	4.33	0.0787	1.0000	$2,089.40	$482.88
1947	76.50	$18,035.18	55.00	4.07	0.0740	1.0000	$1,334.91	$327.91
1946	77.50	$14,784.99	55.00	3.82	0.0694	1.0000	$1,025.90	$268.82
1945	78.50	$4,221.51	55.00	3.56	0.0648	1.0000	$273.55	$76.75
1944	79.50	$3,347.90	55.00	3.32	0.0603	1.0000	$201.79	$60.87
1943	80.50	$938.63	55.00	3.05	0.0554	1.0000	$51.98	$17.07
1942	81.50	$3,837.48	55.00	2.79	0.0508	1.0000	$194.76	$69.77
1941	82.50	$8,173.24	55.00	2.54	0.0462	1.0000	$377.58	$148.60
1940	83.50	$4,515.89	55.00	2.30	0.0418	1.0000	$188.57	$82.11
		$278,093,550.44	55.00	29.71	0.5402	1.0000	$150,213,184.22	$5,056,246.37

Remaining Life Depreciation Accrual

Account: PECO Electric 3692 PA
Scenario: PECO Electric Groups 2024
Dispersion: 55.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$278,093,550.44	29.71	$4,964,877.16	1.785326%	3.366047%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($2,559,012.38)	0.50	($23,263.75)	0.909091%	
Total:	$278,093,550.44 *		$4,941,613.41	1.776961%	3.350275%
Average:	$276,814,044.25		$4,941,613.41	1.785174%	3.379592%
Grand Total:	$278,093,550.44 *		$4,941,613.41	1.776961%	3.350275%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elec SM Composite 2024

Account: PECO Elec SM Composite
Dispersion: 15.00 - S2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$7,265,817.89	15.00	14.50	0.9667	1.0000	$7,023,623.95	$484,387.86
2022	1.50	$6,016,446.75	15.00	13.50	0.9001	1.0000	$5,415,139.01	$401,096.45
2021	2.50	$4,611,561.45	15.00	12.51	0.8338	1.0000	$3,845,199.04	$307,437.43
2020	3.50	$8,067,474.96	15.00	11.53	0.7687	1.0000	$6,201,137.76	$537,831.66
2019	4.50	$3,940,648.95	15.00	10.58	0.7054	1.0000	$2,779,836.76	$262,709.93
2018	5.50	$5,802,817.36	15.00	9.67	0.6450	1.0000	$3,742,544.77	$386,854.49
2017	6.50	$16,693,359.22	15.00	8.82	0.5880	1.0000	$9,815,289.21	$1,112,890.61
2016	7.50	$10,111,878.87	15.00	8.02	0.5348	1.0000	$5,408,144.74	$674,125.26
2015	8.50	$39,095,530.76	15.00	7.29	0.4857	1.0000	$18,989,515.35	$2,606,368.72
2014	9.50	$93,363,742.33	15.00	6.61	0.4407	1.0000	$41,146,274.78	$6,224,249.49
2013	10.50	$122,641,439.67	15.00	5.99	0.3995	1.0000	$48,997,640.90	$8,176,095.98
2012	11.50	$21,732,331.00	15.00	5.43	0.3619	1.0000	$7,865,440.66	$1,448,822.07
2011	12.50	$2,318,006.73	15.00	4.92	0.3277	1.0000	$759,548.34	$154,533.78
		$341,661,055.94	15.00	7.11	0.4741	1.0000	$161,989,335.26	$22,777,403.73

Remaining Life Depreciation Accrual

Account: PECO Elec SM Composite
Scenario: PECO Elec SM Composite 2024
Dispersion: 15.00 - S2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$341,661,055.94	7.11	$20,455,568.04	5.987094%	14.061051%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($19,416,747.38)	0.50	($647,224.91)	3.333333%	
Total:	$341,661,055.94 *		$19,808,343.13	5.797659%	13.616152%
Average:	$331,952,682.25		$19,808,343.13	5.967219%	14.589800%
Grand Total:	$341,661,055.94 *		$19,808,343.13	5.797659%	13.616152%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elect 3701 Composite 2024

Account: PECO Electric 3700 PA
Dispersion: 35.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$696,157.58	35.00	34.55	0.9871	1.0000	$687,160.69	$19,890.22
2022	1.50	$902,371.54	35.00	33.65	0.9614	1.0000	$867,511.95	$25,782.04
2021	2.50	$252,974.55	35.00	32.76	0.9359	1.0000	$236,753.42	$7,227.84
2020	3.50	$310,553.45	35.00	31.87	0.9106	1.0000	$282,788.91	$8,872.96
2019	4.50	$411,632.70	35.00	30.99	0.8855	1.0000	$364,520.96	$11,760.93
2018	5.50	$391,031.11	35.00	30.13	0.8607	1.0000	$336,575.19	$11,172.32
2017	6.50	$385,988.50	35.00	29.27	0.8362	1.0000	$322,753.78	$11,028.24
2016	7.50	$244,754.76	35.00	28.42	0.8119	1.0000	$198,710.75	$6,992.99
2015	8.50	$1,038,877.16	35.00	27.57	0.7878	1.0000	$818,456.64	$29,682.20
2014	9.50	$482,213.62	35.00	26.74	0.7641	1.0000	$368,435.90	$13,777.53
2013	10.50	$239,279.78	35.00	25.92	0.7406	1.0000	$177,198.76	$6,836.57
		$5,355,834.75	35.00	30.46	0.8702	1.0000	$4,660,866.95	$153,023.85

Remaining Life Depreciation Accrual

Account: PECO Electric 3700 PA
Scenario: PECO Elect 3701 Composite 2024
Dispersion: 35.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$5,355,834.75	30.46	$148,684.13	2.776115%	3.283163%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($25,462.24)	0.50	($363.75)	1.428586%	
Total:	$5,355,834.75 *		$148,320.38	2.769323%	3.275131%
Average:	$5,343,103.63		$148,320.38	2.775922%	3.284364%
Grand Total:	$5,355,834.75 *		$148,320.38	2.769323%	3.275131%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3710 PA
Dispersion: 36.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1999	24.50	$156,401.81	36.00	12.86	0.3574	1.0000	$55,891.07	$4,344.49
1998	25.50	$742,575.59	36.00	12.08	0.3356	1.0000	$249,181.33	$20,627.10
1997	26.50	$51,638.40	36.00	11.32	0.3144	1.0000	$16,232.68	$1,434.40
1996	27.50	$24,135.77	36.00	10.58	0.2938	1.0000	$7,090.83	$670.44
1995	28.50	$36,305.98	36.00	9.85	0.2737	1.0000	$9,938.73	$1,008.50
1994	29.50	$19,065.30	36.00	9.15	0.2542	1.0000	$4,847.32	$529.59
		$1,030,122.85	36.00	11.99	0.3331	1.0000	$343,181.96	$28,614.52

01/07/2024

Remaining Life Depreciation Accrual

Account: PECO Electric 3710 PA
Scenario: PECO Electric Groups 2024
Dispersion: 36.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,030,122.85	11.99	$4,544.59	0.441169%	8.338003%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($21,189.23)	0.50	($294.29)	1.388866%	
Total:	$1,030,122.85 *		$4,250.30	0.412601%	7.798066%
Average:	$1,019,528.24		$4,250.30	0.416889%	9.679590%
Grand Total:	$1,030,122.85 *		$4,250.30	0.412601%	7.798066%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elect 371.1 Account 2024

Account: PECO Electric 3711 ACT 129 DLC PA

Dispersion: 15.00 - S2

Average Net Salvage Rate: 0.00%

Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2018	5.50	$36.66	15.00	9.67	0.6450	1.0000	$23.64	$2.44
2012	11.50	$2,805,973.06	15.00	5.43	0.3619	1.0000	$1,015,547.51	$187,064.87
2011	12.50	$7,305,107.16	15.00	4.92	0.3277	1.0000	$2,393,686.76	$487,007.14
2010	13.50	$2,631,142.96	15.00	4.45	0.2964	1.0000	$779,785.67	$175,409.53
		$12,742,259.84	15.00	4.93	0.3288	1.0000	$4,189,043.58	$849,483.99

Remaining Life Depreciation Accrual

Account: PECO Electric 3711 ACT 129 DLC PA
Scenario: PECO Elect 371.1 Account 2024
Dispersion: 15.00 - S2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$12,742,259.84	4.93	$620,251.61	4.867674%	20.278711%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,367,729.99)	0.50	($45,591.00)	3.333333%	
Total:	$12,742,259.84 *		$574,660.61	4.509880%	18.788143%
Average:	$12,058,394.85		$574,660.61	4.765648%	24.198586%
Grand Total:	$12,742,259.84 *		$574,660.61	4.509880%	18.788143%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3730 PA
Dispersion: 24.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$379,819.80	24.00	23.58	0.9825	1.0000	$373,171.52	$15,825.83
2022	1.50	$588,539.32	24.00	22.85	0.9523	1.0000	$560,459.65	$24,522.47
2021	2.50	$510,276.76	24.00	22.21	0.9256	1.0000	$472,303.21	$21,261.53
2020	3.50	$374,599.81	24.00	21.63	0.9012	1.0000	$337,582.03	$15,608.33
2019	4.50	$364,962.41	24.00	21.09	0.8786	1.0000	$320,669.69	$15,206.77
2018	5.50	$361,869.16	24.00	20.58	0.8575	1.0000	$310,304.85	$15,077.88
2017	6.50	$2,446,954.19	24.00	20.10	0.8376	1.0000	$2,049,490.99	$101,956.42
2016	7.50	$377,892.52	24.00	19.65	0.8186	1.0000	$309,354.77	$15,745.52
2015	8.50	$396,220.20	24.00	19.21	0.8006	1.0000	$317,195.73	$16,509.18
2014	9.50	$361,200.58	24.00	18.80	0.7832	1.0000	$282,894.81	$15,050.02
2013	10.50	$357,325.69	24.00	18.40	0.7665	1.0000	$273,880.45	$14,888.57
2012	11.50	$545,893.13	24.00	18.01	0.7503	1.0000	$409,560.01	$22,745.55
2011	12.50	$399,117.20	24.00	17.63	0.7344	1.0000	$293,116.97	$16,629.88
2010	13.50	$339,702.96	24.00	17.25	0.7189	1.0000	$244,220.29	$14,154.29
2009	14.50	$219,670.93	24.00	16.89	0.7038	1.0000	$154,594.09	$9,152.96
2008	15.50	$142,863.70	24.00	16.53	0.6889	1.0000	$98,418.84	$5,952.65
2007	16.50	$103,094.27	24.00	16.18	0.6744	1.0000	$69,523.23	$4,295.59
2006	17.50	$142,931.94	24.00	15.84	0.6601	1.0000	$94,353.91	$5,955.50
2005	18.50	$326,195.23	24.00	15.51	0.6462	1.0000	$210,784.66	$13,591.47
2004	19.50	$591,787.52	24.00	15.18	0.6325	1.0000	$374,330.15	$24,657.81
2003	20.50	$1,474,992.52	24.00	14.86	0.6192	1.0000	$913,272.75	$61,458.02
2002	21.50	$382,008.38	24.00	14.55	0.6061	1.0000	$231,530.04	$15,917.02
2001	22.50	$1,760,575.06	24.00	14.24	0.5932	1.0000	$1,044,453.40	$73,357.29
2000	23.50	$46,363.07	24.00	13.94	0.5807	1.0000	$26,921.43	$1,931.79
1999	24.50	$8,124,017.10	24.00	13.64	0.5683	1.0000	$4,617,222.29	$338,500.71
1998	25.50	$10,547,564.50	24.00	13.35	0.5563	1.0000	$5,867,199.33	$439,481.85
1997	26.50	$3,663,537.22	24.00	13.07	0.5444	1.0000	$1,994,490.88	$152,647.38
1996	27.50	$1,682,176.36	24.00	12.79	0.5328	1.0000	$896,309.73	$70,090.68
1995	28.50	$1,617,319.08	24.00	12.51	0.5214	1.0000	$843,310.17	$67,388.30
1994	29.50	$375,221.58	24.00	12.25	0.5103	1.0000	$191,457.85	$15,634.23
1993	30.50	$273,166.55	24.00	11.98	0.4993	1.0000	$136,387.20	$11,381.94
1992	31.50	$267,634.50	24.00	11.72	0.4885	1.0000	$130,747.56	$11,151.44

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3730 PA
Dispersion: 24.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$325,591.50	24.00	11.47	0.4780	1.0000	$155,625.07	$13,566.31
1990	33.50	$377,917.23	24.00	11.22	0.4676	1.0000	$176,727.65	$15,746.55
1989	34.50	$252,129.72	24.00	10.98	0.4575	1.0000	$115,340.85	$10,505.41
1988	35.50	$418,818.79	24.00	10.74	0.4475	1.0000	$187,411.30	$17,450.78
1987	36.50	$230,470.76	24.00	10.50	0.4377	1.0000	$100,869.66	$9,602.95
1986	37.50	$123,552.62	24.00	10.27	0.4280	1.0000	$52,882.97	$5,148.03
1985	38.50	$542,293.74	24.00	10.05	0.4185	1.0000	$226,975.15	$22,595.57
1984	39.50	$493,539.18	24.00	9.82	0.4093	1.0000	$202,003.94	$20,564.13
1983	40.50	$474,967.40	24.00	9.60	0.4001	1.0000	$190,045.93	$19,790.31
1982	41.50	$296,105.65	24.00	9.39	0.3911	1.0000	$115,817.91	$12,337.74
1981	42.50	$166,024.69	24.00	9.18	0.3823	1.0000	$63,471.58	$6,917.70
1980	43.50	$171,593.70	24.00	8.97	0.3736	1.0000	$64,105.10	$7,149.74
1979	44.50	$217,095.55	24.00	8.76	0.3650	1.0000	$79,248.25	$9,045.65
1978	45.50	$160,314.50	24.00	8.56	0.3567	1.0000	$57,180.87	$6,679.77
1977	46.50	$224,121.95	24.00	8.36	0.3484	1.0000	$78,081.82	$9,338.41
1976	47.50	$158,436.52	24.00	8.17	0.3402	1.0000	$53,905.12	$6,601.52
1975	48.50	$91,536.22	24.00	7.97	0.3322	1.0000	$30,408.34	$3,814.01
1974	49.50	$85,812.74	24.00	7.78	0.3243	1.0000	$27,828.86	$3,575.53
1973	50.50	$83,017.32	24.00	7.60	0.3165	1.0000	$26,276.19	$3,459.06
1972	51.50	$113,325.79	24.00	7.41	0.3089	1.0000	$35,008.85	$4,721.91
1971	52.50	$71,076.65	24.00	7.23	0.3014	1.0000	$21,420.08	$2,961.53
1970	53.50	$20,608.54	24.00	7.05	0.2939	1.0000	$6,057.16	$858.69
1969	54.50	$9,846.37	24.00	6.88	0.2866	1.0000	$2,821.69	$410.27
1968	55.50	$7,987.60	24.00	6.70	0.2793	1.0000	$2,231.27	$332.82
1967	56.50	$8,912.04	24.00	6.53	0.2722	1.0000	$2,425.93	$371.34
1966	57.50	$13,155.09	24.00	6.37	0.2653	1.0000	$3,489.78	$548.13
1965	58.50	$13,780.06	24.00	6.20	0.2583	1.0000	$3,559.91	$574.17
1964	59.50	$1,117.48	24.00	6.04	0.2515	1.0000	$281.03	$46.56
1963	60.50	$11,314.50	24.00	5.87	0.2447	1.0000	$2,769.04	$471.44
1962	61.50	$15,941.86	24.00	5.71	0.2381	1.0000	$3,795.14	$664.24
1961	62.50	$5,062.71	24.00	5.56	0.2315	1.0000	$1,171.95	$210.95
		$44,730,961.71	24.00	14.24	0.5933	1.0000	$26,538,750.88	$1,863,790.07

Remaining Life Depreciation Accrual

Account: PECO Electric 3730 PA
Scenario: PECO Electric Groups 2024
Dispersion: 24.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$44,730,961.71	14.24	$769,987.17	1.721374%	7.022900%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($2,272,966.66)	0.50	($47,353.47)	2.083333%	
Total:	$44,730,961.71 *		$722,633.70	1.615511%	6.590999%
Average:	$43,594,478.38		$722,633.70	1.657627%	7.353206%
Grand Total:	$44,730,961.71 *		$722,633.70	1.615511%	6.590999%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3731 PA
Dispersion: 24.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	($1,529.01)	24.00	23.58	0.9825	1.0000	($1,502.25)	($63.71)
2022	1.50	$3,498.59	24.00	22.85	0.9523	1.0000	$3,331.67	$145.77
2021	2.50	$1,023.98	24.00	22.21	0.9256	1.0000	$947.78	$42.67
2020	3.50	$26,519.75	24.00	21.63	0.9012	1.0000	$23,899.08	$1,104.99
2019	4.50	$133,228.95	24.00	21.09	0.8786	1.0000	$117,059.96	$5,551.21
2018	5.50	$31,469.13	24.00	20.58	0.8575	1.0000	$26,984.96	$1,311.21
2017	6.50	$92,621.91	24.00	20.10	0.8376	1.0000	$77,577.17	$3,859.25
2016	7.50	$74,243.99	24.00	19.65	0.8186	1.0000	$60,778.48	$3,093.50
2015	8.50	$98,042.89	24.00	19.21	0.8006	1.0000	$78,488.64	$4,085.12
2014	9.50	$81,369.08	24.00	18.80	0.7832	1.0000	$63,728.83	$3,390.38
2013	10.50	$112,631.63	24.00	18.40	0.7665	1.0000	$86,329.09	$4,692.98
2012	11.50	$95,438.38	24.00	18.01	0.7503	1.0000	$71,603.29	$3,976.60
2011	12.50	$80,411.26	24.00	17.63	0.7344	1.0000	$59,055.10	$3,350.47
2010	13.50	$160,004.99	24.00	17.25	0.7189	1.0000	$115,031.27	$6,666.87
2009	14.50	$54,986.70	24.00	16.89	0.7038	1.0000	$38,697.06	$2,291.11
2008	15.50	$105,623.45	24.00	16.53	0.6889	1.0000	$72,764.03	$4,400.98
2007	16.50	$13,050.09	24.00	16.18	0.6744	1.0000	$8,800.53	$543.75
2006	17.50	$5,221.05	24.00	15.84	0.6601	1.0000	$3,446.58	$217.54
2005	18.50	$5,963.37	24.00	15.51	0.6462	1.0000	$3,853.48	$248.47
2004	19.50	$2,712.05	24.00	15.18	0.6325	1.0000	$1,715.48	$113.00
2003	20.50	$23,258.72	24.00	14.86	0.6192	1.0000	$14,401.13	$969.11
2002	21.50	$88,697.49	24.00	14.55	0.6061	1.0000	$53,758.33	$3,695.73
2001	22.50	$263,404.01	24.00	14.24	0.5932	1.0000	$156,263.27	$10,975.17
2000	23.50	$18,009.23	24.00	13.94	0.5807	1.0000	$10,457.34	$750.38
1999	24.50	$46,895.59	24.00	13.64	0.5683	1.0000	$26,652.75	$1,953.98
1998	25.50	$387,486.62	24.00	13.35	0.5563	1.0000	$215,543.72	$16,145.28
1997	26.50	$18,305.59	24.00	13.07	0.5444	1.0000	$9,965.87	$762.73
1996	27.50	$7,033.41	24.00	12.79	0.5328	1.0000	$3,747.59	$293.06
1995	28.50	$6,930.41	24.00	12.51	0.5214	1.0000	$3,613.69	$288.77
1986	37.50	$29.02	24.00	10.27	0.4280	1.0000	$12.42	$1.21
1985	38.50	$44.35	24.00	10.05	0.4185	1.0000	$18.56	$1.85
		$2,036,626.67	24.00	16.58	0.6909	1.0000	$1,407,024.89	$84,859.44

Remaining Life Depreciation Accrual

Account: PECO Electric 3731 PA
Scenario: PECO Electric Groups 2024
Dispersion: 24.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$2,036,626.67	16.58	$75,265.16	3.695580%	6.031126%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($81,203.26)	0.50	($1,691.73)	2.083328%	
Total:	$2,036,626.67 *		$73,573.43	3.612514%	5.895565%
Average:	$1,996,025.04		$73,573.43	3.685997%	6.093826%
Grand Total:	$2,036,626.67 *		$73,573.43	3.612514%	5.895565%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3732 PA
Dispersion: 24.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$1,669,603.49	24.00	23.58	0.9825	1.0000	$1,640,379.14	$69,566.81
2022	1.50	$1,573,399.44	24.00	22.85	0.9523	1.0000	$1,498,331.33	$65,558.31
2021	2.50	$1,462,898.29	24.00	22.21	0.9256	1.0000	$1,354,032.98	$60,954.10
2020	3.50	$1,074,196.59	24.00	21.63	0.9012	1.0000	$968,044.98	$44,758.19
2019	4.50	$1,264,553.09	24.00	21.09	0.8786	1.0000	$1,111,083.89	$52,689.71
2018	5.50	$1,125,096.40	24.00	20.58	0.8575	1.0000	$964,776.52	$46,879.02
2017	6.50	$4,158,006.22	24.00	20.10	0.8376	1.0000	$3,482,613.74	$173,250.26
2016	7.50	$506,900.45	24.00	19.65	0.8186	1.0000	$414,964.74	$21,120.85
2015	8.50	$291,186.66	24.00	19.21	0.8006	1.0000	$233,110.69	$12,132.78
2014	9.50	$213,769.53	24.00	18.80	0.7832	1.0000	$167,425.79	$8,907.06
2013	10.50	$136,648.73	24.00	18.40	0.7665	1.0000	$104,737.55	$5,693.70
2012	11.50	$197,708.79	24.00	18.01	0.7503	1.0000	$148,332.36	$8,237.87
2011	12.50	$108,021.88	24.00	17.63	0.7344	1.0000	$79,332.70	$4,500.91
2010	13.50	$73,912.27	24.00	17.25	0.7189	1.0000	$53,137.23	$3,079.68
2009	14.50	$65,045.88	24.00	16.89	0.7038	1.0000	$45,776.24	$2,710.25
2008	15.50	$60,707.30	24.00	16.53	0.6889	1.0000	$41,821.28	$2,529.47
2007	16.50	$18,673.93	24.00	16.18	0.6744	1.0000	$12,593.06	$778.08
2006	17.50	$4,624.04	24.00	15.84	0.6601	1.0000	$3,052.48	$192.67
2005	18.50	$3.27	24.00	15.51	0.6462	1.0000	$2.11	$0.14
2004	19.50	$5.86	24.00	15.18	0.6325	1.0000	$3.71	$0.24
2003	20.50	$1,282.20	24.00	14.86	0.6192	1.0000	$793.90	$53.43
2002	21.50	$5,730.53	24.00	14.55	0.6061	1.0000	$3,473.20	$238.77
2001	22.50	$7,277.96	24.00	14.24	0.5932	1.0000	$4,317.62	$303.25
2000	23.50	$415.06	24.00	13.94	0.5807	1.0000	$241.01	$17.29
1999	24.50	$7,372.90	24.00	13.64	0.5683	1.0000	$4,190.33	$307.20
1998	25.50	$54,604.93	24.00	13.35	0.5563	1.0000	$30,374.60	$2,275.21
1997	26.50	$9,677.93	24.00	13.07	0.5444	1.0000	$5,268.83	$403.25
1996	27.50	$20,698.57	24.00	12.79	0.5328	1.0000	$11,028.77	$862.44
1995	28.50	$10,398.21	24.00	12.51	0.5214	1.0000	$5,421.88	$433.26
1994	29.50	$798.54	24.00	12.25	0.5103	1.0000	$407.46	$33.27
1993	30.50	$2,062.26	24.00	11.98	0.4993	1.0000	$1,029.65	$85.93
1992	31.50	$2,632.95	24.00	11.72	0.4885	1.0000	$1,286.28	$109.71

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3732 PA
Dispersion: 24.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$2,967.22	24.00	11.47	0.4780	1.0000	$1,418.26	$123.63
1990	33.50	$2,956.01	24.00	11.22	0.4676	1.0000	$1,382.34	$123.17
1989	34.50	$1,184.09	24.00	10.98	0.4575	1.0000	$541.68	$49.34
1988	35.50	$227.74	24.00	10.74	0.4475	1.0000	$101.91	$9.49
1987	36.50	$418.90	24.00	10.50	0.4377	1.0000	$183.34	$17.45
1986	37.50	$454.68	24.00	10.27	0.4280	1.0000	$194.61	$18.95
1985	38.50	$535.78	24.00	10.05	0.4185	1.0000	$224.25	$22.32
1984	39.50	$251.25	24.00	9.82	0.4093	1.0000	$102.84	$10.47
1983	40.50	$218.23	24.00	9.60	0.4001	1.0000	$87.32	$9.09
1982	41.50	$132.38	24.00	9.39	0.3911	1.0000	$51.78	$5.52
1981	42.50	$2.75	24.00	9.18	0.3823	1.0000	$1.05	$0.11
1980	43.50	$0.36	24.00	8.97	0.3736	1.0000	$0.13	$0.01
1979	44.50	$0.90	24.00	8.76	0.3650	1.0000	$0.33	$0.04
1978	45.50	$0.73	24.00	8.56	0.3567	1.0000	$0.26	$0.03
1974	49.50	$0.40	24.00	7.78	0.3243	1.0000	$0.13	$0.02
1971	52.50	$0.81	24.00	7.23	0.3014	1.0000	$0.24	$0.03
1919	104.50	$0.89	24.00	0.00	0.0000	0.0000	$0.00	$0.00
1918	105.50	$0.95	24.00	0.00	0.0000	0.0000	$0.00	$0.00
1917	106.50	$0.56	24.00	0.00	0.0000	0.0000	$0.00	$0.00
1916	107.50	$0.80	24.00	0.00	0.0000	0.0000	$0.00	$0.00
1915	108.50	$0.36	24.00	0.00	0.0000	0.0000	$0.00	$0.00
1914	109.50	$0.46	24.00	0.00	0.0000	0.0000	$0.00	$0.00
		$14,137,270.40	24.00	21.04	0.8768	1.0000	$12,395,676.48	$589,052.77

Remaining Life Depreciation Accrual

Account: PECO Electric 3732 PA
Scenario: PECO Electric Groups 2024
Dispersion: 24.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$14,137,270.40	21.04	$937,510.76	6.631484%	4.752082%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($326,298.56)	0.50	($6,797.89)	2.083334%	
Total:	$14,137,270.40 *		$930,712.87	6.583399%	4.717625%
Average:	$13,974,121.12		$930,712.87	6.660261%	4.756964%
Grand Total:	$14,137,270.40 *		$930,712.87	6.583399%	4.717625%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3733 PA
Dispersion: 24.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2003	20.50	($6.52)	24.00	14.86	0.6192	1.0000	($4.04)	($0.27)
2002	21.50	$7.10	24.00	14.55	0.6061	1.0000	$4.30	$0.30
2001	22.50	$96.72	24.00	14.24	0.5932	1.0000	$57.38	$4.03
2000	23.50	$8,020.39	24.00	13.94	0.5807	1.0000	$4,657.16	$334.18
1999	24.50	$795,348.18	24.00	13.64	0.5683	1.0000	$452,029.99	$33,139.51
1998	25.50	$1,030,878.48	24.00	13.35	0.5563	1.0000	$573,437.55	$42,953.27
1997	26.50	$354,735.94	24.00	13.07	0.5444	1.0000	$193,124.17	$14,780.66
1996	27.50	$145,037.08	24.00	12.79	0.5328	1.0000	$77,279.74	$6,043.21
1995	28.50	$153,962.44	24.00	12.51	0.5214	1.0000	$80,279.82	$6,415.10
1994	29.50	$65,942.84	24.00	12.25	0.5103	1.0000	$33,647.52	$2,747.62
1993	30.50	$165,557.05	24.00	11.98	0.4993	1.0000	$82,659.69	$6,898.21
1992	31.50	$123,795.25	24.00	11.72	0.4885	1.0000	$60,477.73	$5,158.14
1991	32.50	$137,323.13	24.00	11.47	0.4780	1.0000	$65,637.22	$5,721.80
1990	33.50	$218,921.68	24.00	11.22	0.4676	1.0000	$102,375.63	$9,121.74
1989	34.50	$178,106.10	24.00	10.98	0.4575	1.0000	$81,477.54	$7,421.09
1988	35.50	$247,965.27	24.00	10.74	0.4475	1.0000	$110,958.47	$10,331.89
1987	36.50	$162,745.82	24.00	10.50	0.4377	1.0000	$71,228.62	$6,781.08
1986	37.50	$139,650.24	24.00	10.27	0.4280	1.0000	$59,773.07	$5,818.76
1985	38.50	$177,432.44	24.00	10.05	0.4185	1.0000	$74,263.73	$7,393.02
1984	39.50	$90,923.20	24.00	9.82	0.4093	1.0000	$37,214.56	$3,788.47
1983	40.50	$93,250.15	24.00	9.60	0.4001	1.0000	$37,311.64	$3,885.42
1982	41.50	$103,329.24	24.00	9.39	0.3911	1.0000	$40,415.90	$4,305.39
1981	42.50	$85,402.36	24.00	9.18	0.3823	1.0000	$32,649.50	$3,558.43
1980	43.50	$68,989.98	24.00	8.97	0.3736	1.0000	$25,773.73	$2,874.58
1979	44.50	$102,910.86	24.00	8.76	0.3650	1.0000	$37,566.43	$4,287.95
1978	45.50	$90,886.18	24.00	8.56	0.3567	1.0000	$32,417.22	$3,786.92
1977	46.50	$100,033.87	24.00	8.36	0.3484	1.0000	$34,850.79	$4,168.08
1976	47.50	$116,014.53	24.00	8.17	0.3402	1.0000	$39,471.81	$4,833.94
1975	48.50	$85,636.53	24.00	7.97	0.3322	1.0000	$28,448.46	$3,568.19
1974	49.50	$93,741.83	24.00	7.78	0.3243	1.0000	$30,400.24	$3,905.91
1973	50.50	$95,181.47	24.00	7.60	0.3165	1.0000	$30,126.32	$3,965.89
1972	51.50	$55,121.13	24.00	7.41	0.3089	1.0000	$17,028.14	$2,296.71

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3733 PA
Dispersion: 24.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1971	52.50	$28,007.23	24.00	7.23	0.3014	1.0000	$8,440.42	$1,166.97
1970	53.50	$14,916.81	24.00	7.05	0.2939	1.0000	$4,384.28	$621.53
1969	54.50	$11,545.02	24.00	6.88	0.2866	1.0000	$3,308.47	$481.04
1968	55.50	$9,204.50	24.00	6.70	0.2793	1.0000	$2,571.20	$383.52
1967	56.50	$8,736.44	24.00	6.53	0.2722	1.0000	$2,378.13	$364.02
1966	57.50	$7,471.52	24.00	6.37	0.2653	1.0000	$1,982.05	$311.31
1965	58.50	$839.66	24.00	6.20	0.2583	1.0000	$216.92	$34.99
		$5,367,662.14	24.00	11.49	0.4789	1.0000	$2,570,321.51	$223,652.59

Remaining Life Depreciation Accrual

Account: PECO Electric 3733 PA
Scenario: PECO Electric Groups 2024
Dispersion: 24.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$5,367,662.14	11.49	$35,596.21	0.663160%	8.701347%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($357,319.02)	0.50	($7,444.15)	2.083334%	
Total:	$5,367,662.14 *		$28,152.06	0.524475%	6.881655%
Average:	$5,189,002.63		$28,152.06	0.542533%	12.217238%
Grand Total:	$5,367,662.14 *		$28,152.06	0.524475%	6.881655%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elect 390 Composite 2024

Account: PECO Elect 390 Composite
Dispersion: 45.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$676,226.43	45.00	44.51	0.9892	1.0000	$668,891.43	$15,027.25
2021	2.50	$624,581.25	45.00	42.68	0.9485	1.0000	$592,400.65	$13,879.58
2020	3.50	$1,144,960.38	45.00	41.82	0.9294	1.0000	$1,064,153.06	$25,443.56
2019	4.50	$156,590.35	45.00	41.00	0.9110	1.0000	$142,658.06	$3,479.79
2018	5.50	$83,562.51	45.00	40.19	0.8932	1.0000	$74,638.70	$1,856.94
2017	6.50	$1,441,318.69	45.00	39.42	0.8759	1.0000	$1,262,462.27	$32,029.30
2016	7.50	$935,715.42	45.00	38.66	0.8590	1.0000	$803,820.86	$20,793.68
2015	8.50	$2,014,475.76	45.00	37.92	0.8427	1.0000	$1,697,547.18	$44,766.13
2014	9.50	$1,935,577.56	45.00	37.20	0.8267	1.0000	$1,600,144.90	$43,012.83
2013	10.50	$553,357.27	45.00	36.50	0.8111	1.0000	$448,826.35	$12,296.83
2012	11.50	$2,710,848.28	45.00	35.81	0.7958	1.0000	$2,157,311.30	$60,241.07
2011	12.50	$2,520,260.57	45.00	35.14	0.7809	1.0000	$1,968,020.22	$56,005.79
2010	13.50	$6,218,145.60	45.00	34.48	0.7663	1.0000	$4,764,734.31	$138,181.01
2009	14.50	$585,768.72	45.00	33.84	0.7519	1.0000	$440,447.84	$13,017.08
2008	15.50	$187,650.44	45.00	33.20	0.7378	1.0000	$138,455.51	$4,170.01
2007	16.50	$386,939.74	45.00	32.58	0.7240	1.0000	$280,144.15	$8,598.66
2006	17.50	$229,769.87	45.00	31.97	0.7104	1.0000	$163,233.22	$5,106.00
2005	18.50	$248,118.40	45.00	31.37	0.6971	1.0000	$172,953.71	$5,513.74
2004	19.50	$100,945.76	45.00	30.78	0.6839	1.0000	$69,038.57	$2,243.24
2003	20.50	$3,789,268.44	45.00	30.19	0.6710	1.0000	$2,542,420.42	$84,205.97
2002	21.50	$172,481.25	45.00	29.62	0.6582	1.0000	$113,528.53	$3,832.92
2001	22.50	$672,471.52	45.00	29.05	0.6456	1.0000	$434,180.42	$14,943.81
1999	24.50	$499,294.52	45.00	27.95	0.6210	1.0000	$310,078.37	$11,095.43
1998	25.50	$5,149,515.88	45.00	27.40	0.6090	1.0000	$3,135,803.43	$114,433.69
1997	26.50	$533,722.47	45.00	26.87	0.5970	1.0000	$318,653.12	$11,860.50
1996	27.50	$37,470.65	45.00	26.34	0.5853	1.0000	$21,930.76	$832.68
1995	28.50	$160,864.09	45.00	25.81	0.5736	1.0000	$92,279.24	$3,574.76
1994	29.50	$236,579.53	45.00	25.30	0.5621	1.0000	$132,989.80	$5,257.32
1993	30.50	$2,308,233.21	45.00	24.79	0.5508	1.0000	$1,271,324.28	$51,294.07
1992	31.50	$2,724,668.88	45.00	24.28	0.5395	1.0000	$1,470,049.10	$60,548.20
1991	32.50	$1,028.95	45.00	23.78	0.5284	1.0000	$543.70	$22.87
1990	33.50	$342,603.06	45.00	23.28	0.5174	1.0000	$177,258.40	$7,613.40

Generation Arrangement Report

PECO Elect 390 Composite 2024

Account: PECO Elect 390 Composite
Dispersion: 45.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1989	34.50	$561,979.90	45.00	22.79	0.5065	1.0000	$284,627.77	$12,488.44
1988	35.50	$726,378.66	45.00	22.31	0.4957	1.0000	$360,050.15	$16,141.75
1987	36.50	$295,387.48	45.00	21.82	0.4850	1.0000	$143,257.96	$6,564.17
1986	37.50	$1,335,855.31	45.00	21.35	0.4744	1.0000	$633,699.85	$29,685.67
1985	38.50	$604,008.13	45.00	20.87	0.4639	1.0000	$280,177.27	$13,422.40
1984	39.50	$382,435.67	45.00	20.41	0.4535	1.0000	$173,415.76	$8,498.57
1983	40.50	$124,422.17	45.00	19.94	0.4431	1.0000	$55,133.28	$2,764.94
1982	41.50	$359,862.88	45.00	19.48	0.4329	1.0000	$155,773.89	$7,996.95
1981	42.50	$120,378.95	45.00	19.02	0.4227	1.0000	$50,885.06	$2,675.09
1980	43.50	$514,893.54	45.00	18.57	0.4126	1.0000	$212,454.99	$11,442.08
1979	44.50	$49,431.66	45.00	18.12	0.4026	1.0000	$19,901.71	$1,098.48
1978	45.50	$12,528.42	45.00	17.67	0.3927	1.0000	$4,919.55	$278.41
1976	47.50	$1,405.70	45.00	16.79	0.3730	1.0000	$524.34	$31.24
1975	48.50	$3,532.85	45.00	16.35	0.3633	1.0000	$1,283.44	$78.51
1974	49.50	$1,105,131.83	45.00	15.91	0.3536	1.0000	$390,798.97	$24,558.49
1973	50.50	$8,156.69	45.00	15.48	0.3440	1.0000	$2,806.01	$181.26
1972	51.50	$4,561.76	45.00	15.05	0.3345	1.0000	$1,525.79	$101.37
1971	52.50	$27,057.89	45.00	14.63	0.3250	1.0000	$8,793.85	$601.29
1970	53.50	$3,533.50	45.00	14.20	0.3156	1.0000	$1,115.07	$78.52
1969	54.50	$2,886,056.94	45.00	13.78	0.3062	1.0000	$883,727.53	$64,134.60
1968	55.50	$11,514.21	45.00	13.36	0.2969	1.0000	$3,418.49	$255.87
1967	56.50	$2,284.74	45.00	12.94	0.2876	1.0000	$657.20	$50.77
1966	57.50	$7,150.71	45.00	12.53	0.2784	1.0000	$1,990.93	$158.90
1964	59.50	$35,896.35	45.00	11.71	0.2601	1.0000	$9,338.43	$797.70
1963	60.50	$25,555.62	45.00	11.30	0.2511	1.0000	$6,416.71	$567.90
1962	61.50	$1,494.46	45.00	10.89	0.2421	1.0000	$361.78	$33.21
1961	62.50	$10,696.14	45.00	10.49	0.2331	1.0000	$2,493.27	$237.69
1960	63.50	$6,328.45	45.00	10.09	0.2242	1.0000	$1,418.68	$140.63
1959	64.50	$18,148.40	45.00	9.69	0.2153	1.0000	$3,907.00	$403.30
1958	65.50	$508,021.10	45.00	9.29	0.2065	1.0000	$104,887.11	$11,289.36
1957	66.50	$1,158.59	45.00	8.89	0.1976	1.0000	$228.99	$25.75
1956	67.50	$10,888.67	45.00	8.50	0.1889	1.0000	$2,056.56	$241.97

Generation Arrangement Report

PECO Elect 390 Composite 2024

Account: PECO Elect 390 Composite
Dispersion: 45.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1955	68.50	$1,752,190.13	45.00	8.11	0.1801	1.0000	$315,643.86	$38,937.56
1954	69.50	$959.98	45.00	7.72	0.1714	1.0000	$164.59	$21.33
1952	71.50	$981.95	45.00	6.94	0.1542	1.0000	$151.41	$21.82
1951	72.50	$1,377.12	45.00	6.55	0.1456	1.0000	$200.51	$30.60
1950	73.50	$5,950.18	45.00	6.17	0.1370	1.0000	$815.47	$132.23
1949	74.50	$13,572.45	45.00	5.79	0.1286	1.0000	$1,745.23	$301.61
1948	75.50	$215.87	45.00	5.40	0.1201	1.0000	$25.92	$4.80
1946	77.50	$19,578.90	45.00	4.64	0.1032	1.0000	$2,020.66	$435.09
1941	82.50	$129.90	45.00	2.77	0.0616	1.0000	$8.00	$2.89
1935	88.50	$50.25	45.00	0.60	0.0134	1.0000	$0.68	$1.12
1931	92.50	$1,075.45	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1929	94.50	$8,335.96	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1927	96.50	$5,751.36	45.00	0.00	0.0000	0.0000	$0.00	$0.00
		$50,959,322.32	45.00	28.84	0.6408	1.0000	$32,653,745.58	$1,132,092.43

Remaining Life Depreciation Accrual

Account: PECO Elect 390 Composite
Scenario: PECO Elect 390 Composite 2024
Dispersion: 45.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$50,959,322.32	28.84	$1,207,333.44	2.369210%	3.466960%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($948,632.61)	0.50	($10,540.36)	1.111111%	
Total:	$50,959,322.32 *		$1,196,793.08	2.348526%	3.436693%
Average:	$50,485,006.02		$1,196,793.08	2.370591%	3.484148%
Grand Total:	$50,959,322.32 *		$1,196,793.08	2.348526%	3.436693%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3912 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$89,486.13	15.00	14.50	0.9667	1.0000	$86,503.26	$5,965.74
2022	1.50	$71,991.62	15.00	13.50	0.9000	1.0000	$64,792.46	$4,799.44
2021	2.50	$75,998.40	15.00	12.50	0.8333	1.0000	$63,332.00	$5,066.56
2020	3.50	$181,647.76	15.00	11.50	0.7667	1.0000	$139,263.28	$12,109.85
2018	5.50	$58,420.87	15.00	9.50	0.6333	1.0000	$36,999.88	$3,894.72
2016	7.50	$145,009.33	15.00	7.50	0.5000	1.0000	$72,504.66	$9,667.29
2015	8.50	$252,830.77	15.00	6.50	0.4333	1.0000	$109,560.00	$16,855.38
2013	10.50	$11,777.35	15.00	4.50	0.3000	1.0000	$3,533.21	$785.16
2012	11.50	$1,193.88	15.00	3.50	0.2333	1.0000	$278.57	$79.59
2009	14.50	$78,405.46	15.00	0.50	0.0333	1.0000	$2,613.52	$5,227.03
		$966,761.57	15.00	8.99	0.5993	1.0000	$579,380.84	$64,450.77

Remaining Life Depreciation Accrual

Account: PECO Electric 3912 PA
Scenario: PECO Electric Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$966,761.57	8.99	$67,424.51	6.974265%	11.124077%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($78,405.46)	0.50	($2,613.52)	3.333339%	
Total:	$966,761.57 *		$64,810.99	6.703927%	10.692884%
Average:	$927,558.84		$64,810.99	6.987265%	11.432313%
Grand Total:	$966,761.57 *		$64,810.99	6.703927%	10.692884%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elect 391.3 Composite 2024

Account: PECO Electric 3913 PA
Dispersion: 5.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$2,113,587.48	5.00	4.50	0.9000	1.0000	$1,902,228.73	$422,717.50
2022	1.50	$6,429,077.99	5.00	3.50	0.7000	1.0000	$4,500,354.59	$1,285,815.60
2021	2.50	$3,797,656.95	5.00	2.50	0.5000	1.0000	$1,898,828.48	$759,531.39
2020	3.50	$13,417,123.06	5.00	1.50	0.3000	1.0000	$4,025,136.92	$2,683,424.61
2019	4.50	$3,853,484.29	5.00	0.50	0.1000	1.0000	$385,348.43	$770,696.86
		$29,610,929.77	5.00	2.15	0.4293	1.0000	$12,711,897.15	$5,922,185.95

Remaining Life Depreciation Accrual

Account: PECO Electric 3913 PA
Scenario: PECO Elect 391.3 Composite 2024
Dispersion: 5.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$29,610,929.77	2.15	$6,293,524.03	21.254057%	46.587750%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($3,853,484.29)	0.50	($385,348.43)	10.000000%	
Total:	$29,610,929.77 *		$5,908,175.60	19.952685%	43.735212%
Average:	$27,684,187.63		$5,908,175.60	21.341336%	51.010712%
Grand Total:	$29,610,929.77 *		$5,908,175.60	19.952685%	43.735212%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3930 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	10.50	$44,814.19	15.00	4.50	0.3000	1.0000	$13,444.26	$2,987.61
		$44,814.19	15.00	4.50	0.3000	1.0000	$13,444.26	$2,987.61

Remaining Life Depreciation Accrual

Account: PECO Electric 3930 PA
Scenario: PECO Electric Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$44,814.19	4.50	$4,294.83	9.583641%	22.222222%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$44,814.19 *		$4,294.83	9.583641%	22.222222%
Average:	$44,814.19		$4,294.83	9.583641%	22.222222%
Grand Total:	$44,814.19 *		$4,294.83	9.583641%	22.222222%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elec 394 Composite 2024

Account: PECO Electric 394 Composite
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$4,738,060.61	15.00	14.50	0.9667	1.0000	$4,580,125.26	$315,870.71
2022	1.50	$4,886,735.66	15.00	13.50	0.9000	1.0000	$4,398,062.09	$325,782.38
2021	2.50	$5,304,356.38	15.00	12.50	0.8333	1.0000	$4,420,296.98	$353,623.76
2020	3.50	$5,486,383.02	15.00	11.50	0.7667	1.0000	$4,206,226.98	$365,758.87
2019	4.50	$3,395,255.01	15.00	10.50	0.7000	1.0000	$2,376,678.51	$226,350.33
2018	5.50	$3,579,047.00	15.00	9.50	0.6333	1.0000	$2,266,729.77	$238,603.13
2017	6.50	$4,759,315.83	15.00	8.50	0.5667	1.0000	$2,696,945.64	$317,287.72
2016	7.50	$4,440,979.77	15.00	7.50	0.5000	1.0000	$2,220,489.88	$296,065.32
2015	8.50	$3,157,790.51	15.00	6.50	0.4333	1.0000	$1,368,375.89	$210,519.37
2014	9.50	$3,347,957.09	15.00	5.50	0.3667	1.0000	$1,227,584.27	$223,197.14
2013	10.50	$2,624,053.51	15.00	4.50	0.3000	1.0000	$787,216.05	$174,936.90
2012	11.50	$1,690,962.99	15.00	3.50	0.2333	1.0000	$394,558.03	$112,730.87
2011	12.50	$2,711,264.82	15.00	2.50	0.1667	1.0000	$451,877.47	$180,750.99
2010	13.50	$1,954,316.24	15.00	1.50	0.1000	1.0000	$195,431.62	$130,287.75
2009	14.50	$967,257.27	15.00	0.50	0.0333	1.0000	$32,241.91	$64,483.82
		$53,043,735.71	15.00	8.94	0.5962	1.0000	$31,622,840.35	$3,536,249.05

Remaining Life Depreciation Accrual

Account: PECO Electric 394 Composite
Scenario: PECO Elec 394 Composite 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$53,043,735.71	8.94	$3,645,842.98	6.873277%	11.182579%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($967,257.27)	0.50	($32,241.91)	3.333333%	
Total:	$53,043,735.71 *		$3,613,601.07	6.812494%	11.083686%
Average:	$52,560,107.08		$3,613,601.07	6.875178%	11.250576%
Grand Total:	$53,043,735.71 *		$3,613,601.07	6.812494%	11.083686%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3951 PA
Dispersion: 20.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2007	16.50	$90,148.95	20.00	3.50	0.1750	1.0000	$15,776.07	$4,507.45
2006	17.50	$6,644.07	20.00	2.50	0.1250	1.0000	$830.51	$332.20
2005	18.50	$158,343.65	20.00	1.50	0.0750	1.0000	$11,875.77	$7,917.18
		$255,136.67	20.00	2.23	0.1116	1.0000	$28,482.35	$12,756.83

Remaining Life Depreciation Accrual

Account: PECO Electric 3951 PA
Scenario: PECO Electric Groups 2024
Dispersion: 20.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$255,136.67	2.23	$13,304.74	5.214751%	44.788560%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$255,136.67 *		$13,304.74	5.214751%	44.788560%
Average:	$255,136.67		$13,304.74	5.214751%	44.788560%
Grand Total:	$255,136.67 *		$13,304.74	5.214751%	44.788560%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric 397 2024

Account: PECO Electric 3970 PA
Dispersion: 20.00 - L3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$3,064,070.97	20.00	19.50	0.9750	1.0000	$2,987,469.20	$153,203.55
2022	1.50	$5,453,052.10	20.00	18.50	0.9250	1.0000	$5,044,073.19	$272,652.60
2021	2.50	$7,655,407.28	20.00	17.50	0.8750	1.0000	$6,698,688.07	$382,770.36
2020	3.50	$2,836,476.62	20.00	16.51	0.8253	1.0000	$2,340,965.74	$141,823.83
2019	4.50	$12,638,422.43	20.00	15.52	0.7762	1.0000	$9,809,655.35	$631,921.12
2018	5.50	$7,575,486.42	20.00	14.56	0.7279	1.0000	$5,514,254.33	$378,774.32
2017	6.50	$1,917,212.20	20.00	13.61	0.6807	1.0000	$1,305,063.95	$95,860.61
2016	7.50	$10,021,139.10	20.00	12.69	0.6347	1.0000	$6,360,565.21	$501,056.96
2015	8.50	$6,095,380.11	20.00	11.80	0.5900	1.0000	$3,596,519.94	$304,769.01
2014	9.50	$22,608,194.89	20.00	10.94	0.5470	1.0000	$12,365,792.99	$1,130,409.74
2013	10.50	$6,118,718.60	20.00	10.12	0.5060	1.0000	$3,095,873.43	$305,935.93
2012	11.50	$4,042,135.79	20.00	9.36	0.4679	1.0000	$1,891,322.67	$202,106.79
2011	12.50	$29,800,289.98	20.00	8.67	0.4333	1.0000	$12,911,472.22	$1,490,014.50
2010	13.50	$21,982,152.66	20.00	8.06	0.4029	1.0000	$8,857,690.63	$1,099,107.63
2009	14.50	$533,762.34	20.00	7.54	0.3772	1.0000	$201,320.62	$26,688.12
2007	16.50	$951,922.05	20.00	6.78	0.3388	1.0000	$322,474.67	$47,596.10
		$143,293,823.54	20.00	11.63	0.5813	1.0000	$83,303,202.21	$7,164,691.18

Remaining Life Depreciation Accrual

Account: PECO Electric 3970 PA
Scenario: PECO Electric 397 2024
Dispersion: 20.00 - L3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$143,293,823.54	11.63	$7,862,723.58	5.487134%	8.600739%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($3,737,972.05)	0.50	($93,449.30)	2.500000%	
Total:	$143,293,823.54 *		$7,769,274.28	5.421918%	8.498518%
Average:	$141,424,837.51		$7,769,274.28	5.493571%	8.675889%
Grand Total:	$143,293,823.54 *		$7,769,274.28	5.421918%	8.498518%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Elec 397 SM 2024

Account: PECO Elec 3979 SM Comm Equip PA
Dispersion: 15.00 - S2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2021	2.50	$1,082,746.24	15.00	12.51	0.8338	1.0000	$902,812.39	$72,183.08
2020	3.50	$4,458,402.68	15.00	11.53	0.7687	1.0000	$3,426,991.64	$297,226.85
2019	4.50	$1,391,380.61	15.00	10.58	0.7054	1.0000	$981,516.25	$92,758.71
2018	5.50	$373,868.88	15.00	9.67	0.6450	1.0000	$241,127.88	$24,924.59
2017	6.50	$6,511,622.72	15.00	8.82	0.5880	1.0000	$3,828,675.78	$434,108.18
2016	7.50	$503,900.86	15.00	8.02	0.5348	1.0000	$269,501.72	$33,593.39
2014	9.50	$309,276.33	15.00	6.61	0.4407	1.0000	$136,300.97	$20,618.42
2013	10.50	$1,512,204.37	15.00	5.99	0.3995	1.0000	$604,155.06	$100,813.62
2011	12.50	$23,633,173.38	15.00	4.92	0.3277	1.0000	$7,743,954.07	$1,575,544.89
		$39,776,576.07	15.00	6.84	0.4559	1.0000	$18,135,035.76	$2,651,771.74

Remaining Life Depreciation Accrual

Account: PECO Elec 3979 SM Comm Equip PA
Scenario: PECO Elec 397 SM 2024
Dispersion: 15.00 - S2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$39,776,576.07	6.84	$2,709,877.52	6.812747%	14.622369%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($2,877,463.13)	0.50	($95,915.44)	3.333333%	
Total:	$39,776,576.07 *		$2,613,962.08	6.571612%	14.104814%
Average:	$38,337,844.51		$2,613,962.08	6.818229%	15.291981%
Grand Total:	$39,776,576.07 *		$2,613,962.08	6.571612%	14.104814%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Electric Groups 2024

Account: PECO Electric 3980 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2022	1.50	$139,949.88	15.00	13.50	0.9000	1.0000	$125,954.89	$9,329.99
2021	2.50	$367,584.54	15.00	12.50	0.8333	1.0000	$306,320.45	$24,505.64
2020	3.50	$204,570.31	15.00	11.50	0.7667	1.0000	$156,837.24	$13,638.02
		$712,104.73	15.00	12.41	0.8273	1.0000	$589,112.58	$47,473.65

Remaining Life Depreciation Accrual

Account: PECO Electric 3980 PA
Scenario: PECO Electric Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$712,104.73	12.41	$68,216.65	9.579582%	8.058502%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$712,104.73 *		$68,216.65	9.579582%	8.058502%
Average:	$712,104.73		$68,216.65	9.579582%	8.058502%
Grand Total:	$712,104.73 *		$68,216.65	9.579582%	8.058502%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common 390 Composite 2024

Account: PECO Common 390 Composite
Dispersion: 55.00 - R1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$33,473,165.09	55.00	54.63	0.9932	1.0000	$33,247,078.34	$608,603.00
2022	1.50	$26,231,713.27	55.00	53.89	0.9798	1.0000	$25,701,740.29	$476,940.24
2021	2.50	$14,945,857.59	55.00	53.15	0.9664	1.0000	$14,444,096.31	$271,742.87
2020	3.50	$20,443,382.53	55.00	52.42	0.9531	1.0000	$19,485,565.82	$371,697.86
2019	4.50	$15,786,924.26	55.00	51.70	0.9399	1.0000	$14,838,637.11	$287,034.99
2018	5.50	$7,526,824.12	55.00	50.97	0.9268	1.0000	$6,975,732.46	$136,851.35
2017	6.50	$11,786,114.15	55.00	50.25	0.9137	1.0000	$10,768,940.21	$214,292.98
2016	7.50	$3,535,634.02	55.00	49.54	0.9007	1.0000	$3,184,491.58	$64,284.25
2015	8.50	$3,524,290.56	55.00	48.83	0.8878	1.0000	$3,128,706.69	$64,078.01
2014	9.50	$4,672,130.45	55.00	48.12	0.8749	1.0000	$4,087,531.95	$84,947.83
2013	10.50	$6,479,129.37	55.00	47.41	0.8621	1.0000	$5,585,395.46	$117,802.35
2012	11.50	$4,737,124.82	55.00	46.71	0.8493	1.0000	$4,023,214.34	$86,129.54
2011	12.50	$2,807,741.74	55.00	46.01	0.8366	1.0000	$2,348,941.90	$51,049.85
2010	13.50	$23,784,418.93	55.00	45.32	0.8240	1.0000	$19,597,280.58	$432,443.98
2009	14.50	$13,010,855.37	55.00	44.63	0.8114	1.0000	$10,556,674.67	$236,561.01
2008	15.50	$6,657,810.34	55.00	43.94	0.7988	1.0000	$5,318,540.98	$121,051.10
2007	16.50	$4,705,608.60	55.00	43.25	0.7863	1.0000	$3,700,244.27	$85,556.52
2006	17.50	$172,301.52	55.00	42.57	0.7739	1.0000	$133,345.92	$3,132.75
2005	18.50	$1,307,544.40	55.00	41.88	0.7615	1.0000	$995,727.74	$23,773.53
2004	19.50	$2,314,335.66	55.00	41.21	0.7492	1.0000	$1,733,888.98	$42,078.83
2003	20.50	$21,962,509.57	55.00	40.53	0.7369	1.0000	$16,184,479.01	$399,318.36
2002	21.50	$2,685,959.20	55.00	39.86	0.7247	1.0000	$1,946,456.95	$48,835.62
2001	22.50	$815,059.23	55.00	39.19	0.7125	1.0000	$580,736.90	$14,819.26
2000	23.50	$417,130.00	55.00	38.52	0.7004	1.0000	$292,159.31	$7,584.18
1999	24.50	$1,817,757.87	55.00	37.86	0.6884	1.0000	$1,251,260.42	$33,050.14
1998	25.50	$40,860,513.08	55.00	37.20	0.6764	1.0000	$27,638,006.48	$742,918.42
1997	26.50	$5,090,081.78	55.00	36.55	0.6645	1.0000	$3,382,365.08	$92,546.94
1996	27.50	$2,961,881.86	55.00	35.90	0.6527	1.0000	$1,933,140.17	$53,852.40
1995	28.50	$21,344,897.25	55.00	35.25	0.6409	1.0000	$13,680,533.88	$388,089.04
1994	29.50	$3,045,571.17	55.00	34.61	0.6293	1.0000	$1,916,463.94	$55,374.02
1993	30.50	$6,536,534.74	55.00	33.97	0.6177	1.0000	$4,037,684.07	$118,846.09
1992	31.50	$4,055,727.37	55.00	33.34	0.6062	1.0000	$2,458,701.44	$73,740.50

Generation Arrangement Report

PECO Common 390 Composite 2024

Account: PECO Common 390 Composite
Dispersion: 55.00 - R1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1991	32.50	$2,461,687.57	55.00	32.72	0.5948	1.0000	$1,464,306.27	$44,757.96
1990	33.50	$1,630,818.18	55.00	32.10	0.5835	1.0000	$951,658.46	$29,651.24
1989	34.50	$425,645.00	55.00	31.48	0.5724	1.0000	$243,618.60	$7,739.00
1988	35.50	$1,621,992.40	55.00	30.87	0.5612	1.0000	$910,342.35	$29,490.77
1987	36.50	$1,843,461.39	55.00	30.27	0.5503	1.0000	$1,014,427.53	$33,517.48
1986	37.50	$891,755.86	55.00	29.67	0.5394	1.0000	$481,018.38	$16,213.74
1985	38.50	$583,726.08	55.00	29.07	0.5286	1.0000	$308,576.04	$10,613.20
1984	39.50	$1,747,807.13	55.00	28.49	0.5180	1.0000	$905,292.03	$31,778.31
1983	40.50	$1,107,195.78	55.00	27.91	0.5074	1.0000	$561,794.07	$20,130.83
1982	41.50	$293,436.25	55.00	27.33	0.4970	1.0000	$145,832.17	$5,335.20
1981	42.50	$1,008,275.15	55.00	26.77	0.4867	1.0000	$490,680.36	$18,332.28
1980	43.50	$325,585.69	55.00	26.20	0.4764	1.0000	$155,120.60	$5,919.74
1979	44.50	$74,022.35	55.00	25.65	0.4663	1.0000	$34,519.48	$1,345.86
1978	45.50	$358,408.13	55.00	25.10	0.4563	1.0000	$163,557.75	$6,516.51
1977	46.50	$145,548.13	55.00	24.56	0.4465	1.0000	$64,983.41	$2,646.33
1976	47.50	$91,976.05	55.00	24.02	0.4367	1.0000	$40,169.86	$1,672.29
1975	48.50	$74,766.72	55.00	23.49	0.4271	1.0000	$31,933.51	$1,359.39
1974	49.50	$74,462.49	55.00	22.97	0.4176	1.0000	$31,094.60	$1,353.86
1973	50.50	$9,578.53	55.00	22.45	0.4082	1.0000	$3,909.71	$174.16
1972	51.50	$25,138,086.51	55.00	21.94	0.3989	1.0000	$10,027,195.13	$457,056.12
1971	52.50	$13,150.86	55.00	21.43	0.3897	1.0000	$5,125.17	$239.11
1970	53.50	$4,026,826.49	55.00	20.94	0.3807	1.0000	$1,532,841.50	$73,215.03
1969	54.50	$20,156.13	55.00	20.44	0.3717	1.0000	$7,492.25	$366.48
1968	55.50	$3,016,555.59	55.00	19.96	0.3629	1.0000	$1,094,615.22	$54,846.47
1967	56.50	$588,794.05	55.00	19.48	0.3541	1.0000	$208,517.16	$10,705.35
1966	57.50	$8,710.80	55.00	19.00	0.3455	1.0000	$3,009.80	$158.38
1965	58.50	$230,964.86	55.00	18.54	0.3370	1.0000	$77,842.43	$4,199.36
1964	59.50	$448.18	55.00	18.07	0.3286	1.0000	$147.29	$8.15
1963	60.50	$102,934.00	55.00	17.62	0.3203	1.0000	$32,974.15	$1,871.53
1962	61.50	$13,782.07	55.00	17.17	0.3122	1.0000	$4,302.25	$250.58
1961	62.50	$798,747.44	55.00	16.72	0.3041	1.0000	$242,880.66	$14,522.68
1960	63.50	$41,170.32	55.00	16.29	0.2961	1.0000	$12,190.96	$748.55

Generation Arrangement Report

PECO Common 390 Composite 2024

Account: PECO Common 390 Composite
Dispersion: 55.00 - R1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1959	64.50	$506,068.46	55.00	15.85	0.2882	1.0000	$145,867.16	$9,201.24
1958	65.50	$114,683.49	55.00	15.43	0.2805	1.0000	$32,165.07	$2,085.15
1957	66.50	$45,395.83	55.00	15.00	0.2728	1.0000	$12,383.80	$825.38
1956	67.50	$1,379,385.77	55.00	14.59	0.2652	1.0000	$365,840.23	$25,079.74
1955	68.50	$35,386.50	55.00	14.18	0.2578	1.0000	$9,120.93	$643.39
1954	69.50	$1,992.49	55.00	13.77	0.2504	1.0000	$498.85	$36.23
1953	70.50	$73,915.73	55.00	13.37	0.2431	1.0000	$17,967.57	$1,343.92
1952	71.50	$63,925.13	55.00	12.97	0.2359	1.0000	$15,079.17	$1,162.28
1951	72.50	$16,504.21	55.00	12.58	0.2288	1.0000	$3,776.08	$300.08
1950	73.50	$3,326.06	55.00	12.20	0.2218	1.0000	$737.67	$60.47
1949	74.50	$56,408.83	55.00	11.82	0.2149	1.0000	$12,119.95	$1,025.62
1948	75.50	$238.29	55.00	11.44	0.2080	1.0000	$49.57	$4.33
1947	76.50	$293.41	55.00	11.07	0.2013	1.0000	$59.06	$5.33
1946	77.50	$1,117.60	55.00	10.70	0.1946	1.0000	$217.52	$20.32
1944	79.50	$394,951.08	55.00	9.99	0.1816	1.0000	$71,720.49	$7,180.93
1942	81.50	$3,689.29	55.00	9.29	0.1688	1.0000	$622.86	$67.08
1941	82.50	$1,241.54	55.00	8.94	0.1626	1.0000	$201.87	$22.57
1938	85.50	$8,310.34	55.00	7.94	0.1443	1.0000	$1,199.39	$151.10
1937	86.50	$121.50	55.00	7.61	0.1384	1.0000	$16.82	$2.21
1933	90.50	$25.47	55.00	6.35	0.1155	1.0000	$2.94	$0.46
1931	92.50	$403.82	55.00	5.74	0.1043	1.0000	$42.13	$7.34
1930	93.50	$122.02	55.00	5.44	0.0989	1.0000	$12.07	$2.22
1927	96.50	$13,978.16	55.00	4.55	0.0827	1.0000	$1,156.59	$254.15
1925	98.50	$5,336.67	55.00	3.96	0.0720	1.0000	$384.50	$97.03
1924	99.50	$5,737.55	55.00	3.67	0.0667	1.0000	$382.51	$104.32
1922	101.50	$232.91	55.00	3.06	0.0557	1.0000	$12.97	$4.23
1914	109.50	$1,588.23	55.00	0.52	0.0095	1.0000	$15.15	$28.88
1892	131.50	$59.47	55.00	0.00	0.0000	0.0000	$0.00	$0.00
		$371,001,445.94	55.00	42.56	0.7739	1.0000	$287,101,385.33	$6,745,479.75

Remaining Life Depreciation Accrual

Account: PECO Common 390 Composite
Scenario: PECO Common 390 Composite 2024
Dispersion: 55.00 - R1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$371,001,445.94	42.56	$6,929,864.62	1.867881%	2.349511%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($3,374,318.12)	0.50	($30,675.62)	0.909091%	
Total:	$371,001,445.94 *		$6,899,189.00	1.859612%	2.339111%
Average:	$369,314,286.88		$6,899,189.00	1.868108%	2.352568%
Grand Total:	$371,001,445.94 *		$6,899,189.00	1.859612%	2.339111%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3911 PA
Dispersion: 10.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2019	4.50	$100,572.80	10.00	5.50	0.5500	1.0000	$55,315.04	$10,057.28
		$100,572.80	10.00	5.50	0.5500	1.0000	$55,315.04	$10,057.28

Remaining Life Depreciation Accrual

Account: PECO Common 3911 PA
Scenario: PECO Common Groups 2024
Dispersion: 10.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$100,572.80	5.50	$13,629.47	13.551841%	18.181818%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$100,572.80 *		$13,629.47	13.551841%	18.181818%
Average:	$100,572.80		$13,629.47	13.551841%	18.181818%
Grand Total:	$100,572.80 *		$13,629.47	13.551841%	18.181818%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3912 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$78,661.44	15.00	14.50	0.9667	1.0000	$76,039.39	$5,244.10
2022	1.50	$2,311,205.85	15.00	13.50	0.9000	1.0000	$2,080,085.27	$154,080.39
2021	2.50	$398,753.73	15.00	12.50	0.8333	1.0000	$332,294.78	$26,583.58
2020	3.50	$4,458,491.59	15.00	11.50	0.7667	1.0000	$3,418,176.89	$297,232.77
2019	4.50	$5,306,661.15	15.00	10.50	0.7000	1.0000	$3,714,662.81	$353,777.41
2018	5.50	$1,835,238.77	15.00	9.50	0.6333	1.0000	$1,162,317.89	$122,349.25
2017	6.50	$6,381,677.35	15.00	8.50	0.5667	1.0000	$3,616,283.83	$425,445.16
2016	7.50	$2,471,622.59	15.00	7.50	0.5000	1.0000	$1,235,811.30	$164,774.84
2015	8.50	$765,681.81	15.00	6.50	0.4333	1.0000	$331,795.45	$51,045.45
2014	9.50	$269,581.12	15.00	5.50	0.3667	1.0000	$98,846.41	$17,972.07
2013	10.50	$551,666.18	15.00	4.50	0.3000	1.0000	$165,499.85	$36,777.75
2012	11.50	$264,226.94	15.00	3.50	0.2333	1.0000	$61,652.95	$17,615.13
2011	12.50	$486,527.93	15.00	2.50	0.1667	1.0000	$81,087.99	$32,435.20
2010	13.50	$953,124.79	15.00	1.50	0.1000	1.0000	$95,312.48	$63,541.65
2009	14.50	$68,987.13	15.00	0.50	0.0333	1.0000	$2,299.57	$4,599.14
		$26,602,108.37	15.00	9.29	0.6192	1.0000	$16,472,166.84	$1,773,473.89

Remaining Life Depreciation Accrual

Account: PECO Common 3912 PA
Scenario: PECO Common Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$26,602,108.37	9.29	$2,284,519.85	8.587740%	10.766488%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($68,987.13)	0.50	($2,299.57)	3.333332%	
Total:	$26,602,108.37 *		$2,282,220.28	8.579095%	10.755650%
Average:	$26,567,614.81		$2,282,220.28	8.590234%	10.773163%
Grand Total:	$26,602,108.37 *		$2,282,220.28	8.579095%	10.755650%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common 391.3 Composite 2024

Account: PECO Common 3913 Composite
Dispersion: 5.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$11,521,553.83	5.00	4.50	0.9000	1.0000	$10,369,398.45	$2,304,310.77
2022	1.50	$10,320,951.33	5.00	3.50	0.7000	1.0000	$7,224,665.93	$2,064,190.27
2021	2.50	$7,175,681.06	5.00	2.50	0.5000	1.0000	$3,587,840.53	$1,435,136.21
2020	3.50	$7,191,339.89	5.00	1.50	0.3000	1.0000	$2,157,401.97	$1,438,267.98
2019	4.50	$8,646,094.27	5.00	0.50	0.1000	1.0000	$864,609.43	$1,729,218.85
2018	5.50	$65,435.00	5.00	0.00	0.0000	0.0000	$0.00	$0.00
2012	11.50	($2,682.00)	5.00	0.00	0.0000	0.0000	$0.00	$0.00
		$44,918,373.38	5.00	2.70	0.5388	1.0000	$24,203,916.30	$8,971,124.08

Remaining Life Depreciation Accrual

Account: PECO Common 3913 Composite
Scenario: PECO Common 391.3 Composite 2024
Dispersion: 5.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$44,918,373.38	2.70	$9,048,288.38	20.143847%	37.064767%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($8,646,094.27)	0.50	($864,609.43)	10.000000%	
Total:	$44,918,373.38 *		$8,183,678.95	18.219001%	33.523042%
Average:	$40,595,326.25		$8,183,678.95	20.159165%	40.737005%
Grand Total:	$44,918,373.38 *		$8,183,678.95	18.219001%	33.523042%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3921 PA
Dispersion: 6.00 - L3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2017	6.50	$2,306.80	6.00	1.76	0.2929	1.0000	$675.59	$384.47
2015	8.50	$752.09	6.00	1.30	0.2174	1.0000	$163.47	$125.35
2002	21.50	$64,490.53	6.00	0.00	0.0000	0.0000	$0.00	$0.00
		$67,549.42	6.00	1.65	0.0124	1.0000	$839.07	$509.82

Remaining Life Depreciation Accrual

Account: PECO Common 3921 PA
Scenario: PECO Common Groups 2024
Dispersion: 6.00 - L3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$67,549.42	1.65	($2,075.84)	-3.073064%	60.759875%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,258.68)	0.50	($104.89)	8.333333%	
Total:	$67,549.42 *		($2,180.73)	-3.228343%	63.830012%
Average:	$66,920.08		($2,180.73)	-3.258703%	53.901004%
Grand Total:	$67,549.42 *		($2,180.73)	-3.228343%	63.830012%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3922 PA
Dispersion: 12.00 - S4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$6,093,630.90	12.00	11.50	0.9583	1.0000	$5,839,729.60	$507,802.58
2022	1.50	$3,765,352.71	12.00	10.50	0.8750	1.0000	$3,294,683.61	$313,779.39
2021	2.50	$6,684,602.07	12.00	9.50	0.7917	1.0000	$5,291,976.62	$557,050.17
2020	3.50	$3,531,877.71	12.00	8.50	0.7083	1.0000	$2,501,746.70	$294,323.14
2019	4.50	$4,314,339.78	12.00	7.50	0.6250	1.0000	$2,696,534.26	$359,528.32
2018	5.50	$2,383,578.77	12.00	6.50	0.5419	1.0000	$1,291,610.86	$198,631.56
2017	6.50	$3,254,130.17	12.00	5.52	0.4598	1.0000	$1,496,296.86	$271,177.51
2016	7.50	$5,519,175.80	12.00	4.57	0.3811	1.0000	$2,103,362.01	$459,931.32
2015	8.50	$4,207,764.81	12.00	3.71	0.3095	1.0000	$1,302,101.89	$350,647.07
2014	9.50	$4,266,553.67	12.00	2.98	0.2480	1.0000	$1,058,085.54	$355,546.14
2013	10.50	$1,480,427.12	12.00	2.37	0.1979	1.0000	$292,917.28	$123,368.93
2012	11.50	$51,459.17	12.00	1.90	0.1586	1.0000	$8,159.11	$4,288.26
2010	13.50	$1,034,775.31	12.00	1.26	0.1047	1.0000	$108,390.22	$86,231.28
2009	14.50	($73,442.95)	12.00	1.04	0.0865	1.0000	($6,352.97)	($6,120.25)
2008	15.50	($84,042.38)	12.00	0.87	0.0721	1.0000	($6,058.19)	($7,003.53)
2007	16.50	($5,936.57)	12.00	0.74	0.0613	1.0000	($364.04)	($494.71)
2006	17.50	($17,794.82)	12.00	0.63	0.0527	1.0000	($937.64)	($1,482.90)
2005	18.50	($5,237.68)	12.00	0.54	0.0451	1.0000	($236.09)	($436.47)
		$46,401,213.59	12.00	7.05	0.5877	1.0000	$27,271,645.63	$3,866,767.80

Remaining Life Depreciation Accrual

Account: PECO Common 3922 PA
Scenario: PECO Common Groups 2024
Dispersion: 12.00 - S4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$46,401,213.59	7.05	$3,523,474.48	7.593496%	14.178712%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,874,115.55)	0.50	($78,088.15)	4.166667%	
Total:	$46,401,213.59 *		$3,445,386.33	7.425207%	13.864479%
Average:	$45,464,155.82		$3,445,386.33	7.578248%	14.407765%
Grand Total:	$46,401,213.59 *		$3,445,386.33	7.425207%	13.864479%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3923 PA
Dispersion: 14.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$13,479,643.77	14.00	13.50	0.9643	1.0000	$12,998,644.28	$962,831.70
2022	1.50	$8,442,335.45	14.00	12.50	0.8930	1.0000	$7,539,292.42	$603,023.96
2021	2.50	$9,812,135.57	14.00	11.51	0.8219	1.0000	$8,065,058.43	$700,866.83
2020	3.50	$5,257,912.78	14.00	10.52	0.7512	1.0000	$3,949,941.43	$375,565.20
2019	4.50	$13,483,377.98	14.00	9.54	0.6812	1.0000	$9,184,860.60	$963,098.43
2018	5.50	$4,552,920.78	14.00	8.57	0.6123	1.0000	$2,787,531.08	$325,208.63
2017	6.50	$7,617,326.79	14.00	7.63	0.5449	1.0000	$4,151,013.47	$544,094.77
2016	7.50	$9,193,523.00	14.00	6.72	0.4799	1.0000	$4,411,718.37	$656,680.21
2015	8.50	$3,476,528.53	14.00	5.85	0.4178	1.0000	$1,452,346.24	$248,323.47
2014	9.50	$10,095,457.91	14.00	5.03	0.3591	1.0000	$3,625,510.89	$721,104.14
2013	10.50	$7,243,874.33	14.00	4.26	0.3043	1.0000	$2,204,402.91	$517,419.60
2012	11.50	$2,913,595.85	14.00	3.55	0.2533	1.0000	$738,085.17	$208,113.99
2011	12.50	$3,620,081.35	14.00	2.89	0.2062	1.0000	$746,293.89	$258,577.24
2010	13.50	$5,767,850.51	14.00	2.31	0.1652	1.0000	$953,094.40	$411,989.32
2009	14.50	$1,442,949.26	14.00	1.86	0.1326	1.0000	$191,319.74	$103,067.80
2008	15.50	$1,991,682.37	14.00	1.50	0.1072	1.0000	$213,445.32	$142,263.03
2006	17.50	($211.56)	14.00	0.95	0.0681	1.0000	($14.41)	($15.11)
2004	19.50	($176,825.88)	14.00	0.54	0.0389	1.0000	($6,870.46)	($12,630.42)
1997	26.50	$200,155.65	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1994	29.50	$141,407.95	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	31.50	($345,713.56)	14.00	0.00	0.0000	0.0000	$0.00	$0.00
		$108,210,008.83	14.00	8.18	0.5841	1.0000	$63,205,673.79	$7,729,582.77

Remaining Life Depreciation Accrual

Account: PECO Common 3923 PA
Scenario: PECO Common Groups 2024
Dispersion: 14.00 - R4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$108,210,008.83	8.18	$7,311,901.39	6.757140%	12.229255%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($4,803,891.16)	0.50	($171,567.54)	3.571429%	
Total:	$108,210,008.83 *		$7,140,333.85	6.598589%	11.942306%
Average:	$105,808,063.25		$7,140,333.85	6.748383%	12.442142%
Grand Total:	$108,210,008.83 *		$7,140,333.85	6.598589%	11.942306%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3924 PA
Dispersion: 11.00 - L2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$142,055.76	11.00	10.50	0.9546	1.0000	$135,611.18	$12,914.16
2009	14.50	$57,897.77	11.00	3.44	0.3127	1.0000	$18,106.11	$5,263.43
2002	21.50	$44,306.19	11.00	1.84	0.1673	1.0000	$7,414.07	$4,027.84
1995	28.50	$177,146.57	11.00	0.59	0.0541	1.0000	$9,579.26	$16,104.23
		$421,406.29	11.00	4.46	0.4051	1.0000	$170,710.62	$38,309.66

Remaining Life Depreciation Accrual

Account: PECO Common 3924 PA
Scenario: PECO Common Groups 2024
Dispersion: 11.00 - L2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$421,406.29	4.46	$19,409.07	4.605785%	22.441289%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($182,249.82)	0.50	($8,284.08)	4.545453%	
Total:	$421,406.29 *		$11,124.99	2.639968%	12.863012%
Average:	$330,281.38		$11,124.99	3.368337%	-239.933341%
Grand Total:	$421,406.29 *		$11,124.99	2.639968%	12.863012%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3925 PA
Dispersion: 14.00 - L1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$401,515.30	14.00	13.52	0.9655	1.0000	$387,650.94	$28,679.66
2022	1.50	$124,663.73	14.00	12.58	0.8984	1.0000	$112,003.70	$8,904.55
2021	2.50	$238,124.45	14.00	11.69	0.8351	1.0000	$198,855.54	$17,008.89
2020	3.50	$243,537.12	14.00	10.87	0.7761	1.0000	$189,015.47	$17,395.51
2019	4.50	$32,124.54	14.00	10.10	0.7217	1.0000	$23,185.62	$2,294.61
2018	5.50	$369,084.30	14.00	9.41	0.6720	1.0000	$248,024.13	$26,363.16
2017	6.50	$666,229.90	14.00	8.79	0.6278	1.0000	$418,231.35	$47,587.85
2016	7.50	$850,547.86	14.00	8.25	0.5894	1.0000	$501,337.29	$60,753.42
2015	8.50	$445,680.25	14.00	7.79	0.5566	1.0000	$248,050.86	$31,834.30
2014	9.50	$303,236.60	14.00	7.39	0.5280	1.0000	$160,106.80	$21,659.76
2013	10.50	$70,130.41	14.00	7.04	0.5028	1.0000	$35,263.84	$5,009.31
2012	11.50	$98,806.05	14.00	6.72	0.4802	1.0000	$47,449.30	$7,057.58
2011	12.50	$45,336.50	14.00	6.43	0.4594	1.0000	$20,826.61	$3,238.32
2010	13.50	$308,073.67	14.00	6.15	0.4396	1.0000	$135,434.90	$22,005.26
2009	14.50	$7,165.37	14.00	5.89	0.4205	1.0000	$3,013.08	$511.81
2008	15.50	($265,209.35)	14.00	5.62	0.4017	1.0000	($106,522.20)	($18,943.52)
2007	16.50	$589,268.67	14.00	5.36	0.3830	1.0000	$225,670.54	$42,090.62
2006	17.50	$50,554.48	14.00	5.10	0.3644	1.0000	$18,424.22	$3,611.03
2005	18.50	$23,623.28	14.00	4.85	0.3461	1.0000	$8,177.13	$1,687.38
2004	19.50	$9,379.42	14.00	4.59	0.3282	1.0000	$3,078.24	$669.96
2003	20.50	$23,049.70	14.00	4.35	0.3107	1.0000	$7,160.84	$1,646.41
2002	21.50	$174,201.67	14.00	4.11	0.2937	1.0000	$51,164.71	$12,442.98
2001	22.50	$3,706.93	14.00	3.88	0.2773	1.0000	$1,027.87	$264.78
2000	23.50	$67,159.32	14.00	3.66	0.2614	1.0000	$17,556.49	$4,797.09
1997	26.50	$232,446.39	14.00	3.04	0.2173	1.0000	$50,502.01	$16,603.31
1996	27.50	$180,164.09	14.00	2.85	0.2036	1.0000	$36,687.10	$12,868.86
1995	28.50	$71,710.56	14.00	2.67	0.1907	1.0000	$13,672.25	$5,122.18
1994	29.50	($36,535.68)	14.00	2.49	0.1781	1.0000	($6,506.42)	($2,609.69)
1988	35.50	$9,324.38	14.00	1.57	0.1123	1.0000	$1,047.03	$666.03
1978	45.50	$14,407.27	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1976	47.50	$1,544.50	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1975	48.50	$25,351.71	14.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3925 PA
Dispersion: 14.00 - L1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1974	49.50	$814.23	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	50.50	$67,709.54	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	51.50	$4,524.32	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	52.50	$6,644.50	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1970	53.50	$27,731.60	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	54.50	$11,345.85	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	55.50	$54,611.08	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1967	56.50	$23,398.38	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1966	57.50	$3,152.61	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	60.50	$1,026.82	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	61.50	$972.68	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1961	62.50	$3,539.00	14.00	0.00	0.0000	0.0000	$0.00	$0.00
1960	63.50	$5,673.50	14.00	0.00	0.0000	0.0000	$0.00	$0.00
		$5,589,547.50	14.00	8.00	0.5456	1.0000	$3,049,589.28	$381,221.42

Remaining Life Depreciation Accrual

Account: PECO Common 3925 PA
Scenario: PECO Common Groups 2024
Dispersion: 14.00 - L1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$5,589,547.50	8.00	$277,884.41	4.971501%	12.500747%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($457,450.74)	0.50	($16,337.53)	3.571429%	
Total:	$5,589,547.50 *		$261,546.88	4.679214%	11.765796%
Average:	$5,360,822.13		$261,546.88	4.878858%	13.115266%
Grand Total:	$5,589,547.50 *		$261,546.88	4.679214%	11.765796%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3926 PA
Dispersion: 15.00 - L2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$92,545.00	15.00	14.50	0.9667	1.0000	$89,464.11	$6,169.67
2022	1.50	$200,469.85	15.00	13.52	0.9010	1.0000	$180,629.34	$13,364.66
2021	2.50	$382,589.00	15.00	12.56	0.8375	1.0000	$320,425.66	$25,505.93
2020	3.50	$880,312.65	15.00	11.65	0.7769	1.0000	$683,877.44	$58,687.51
2019	4.50	$10,000.00	15.00	10.79	0.7191	1.0000	$7,191.28	$666.67
2018	5.50	$118,132.30	15.00	9.97	0.6644	1.0000	$78,482.81	$7,875.49
2016	7.50	$125,532.09	15.00	8.54	0.5696	1.0000	$71,503.64	$8,368.81
2015	8.50	$200,945.00	15.00	7.98	0.5318	1.0000	$106,858.77	$13,396.33
2014	9.50	$322,483.80	15.00	7.50	0.5002	1.0000	$161,294.11	$21,498.92
2012	11.50	$248,450.64	15.00	6.77	0.4513	1.0000	$112,115.54	$16,563.38
2011	12.50	$5,537.55	15.00	6.48	0.4318	1.0000	$2,391.13	$369.17
2010	13.50	$280,071.99	15.00	6.21	0.4143	1.0000	$116,030.85	$18,671.47
2009	14.50	$231,325.16	15.00	5.97	0.3979	1.0000	$92,042.82	$15,421.68
2008	15.50	($7,679.32)	15.00	5.73	0.3819	1.0000	($2,932.60)	($511.95)
2007	16.50	$218,596.62	15.00	5.49	0.3659	1.0000	$79,987.04	$14,573.11
2006	17.50	$906,063.59	15.00	5.25	0.3497	1.0000	$316,886.63	$60,404.24
2005	18.50	$310,885.69	15.00	5.00	0.3332	1.0000	$103,589.30	$20,725.71
2003	20.50	$75,707.23	15.00	4.50	0.2998	1.0000	$22,696.29	$5,047.15
2002	21.50	$1,162,784.26	15.00	4.25	0.2831	1.0000	$329,167.90	$77,518.95
1996	27.50	$28,685.34	15.00	2.86	0.1909	1.0000	$5,474.81	$1,912.36
1995	28.50	$70,184.76	15.00	2.65	0.1770	1.0000	$12,421.25	$4,678.98
1994	29.50	$20,914.19	15.00	2.45	0.1635	1.0000	$3,419.96	$1,394.28
1993	30.50	$27,544.80	15.00	2.25	0.1502	1.0000	$4,138.29	$1,836.32
1992	31.50	$6,119.39	15.00	2.06	0.1374	1.0000	$840.78	$407.96
1983	40.50	$2,890.72	15.00	0.15	0.0100	1.0000	$28.91	$192.71
1974	49.50	$3,888.93	15.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	50.50	$3,536.26	15.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	51.50	$17,323.55	15.00	0.00	0.0000	0.0000	$0.00	$0.00
1965	58.50	$84,406.50	15.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	61.50	$57.56	15.00	0.00	0.0000	0.0000	$0.00	$0.00
1946	77.50	$920.22	15.00	0.00	0.0000	0.0000	$0.00	$0.00
		$6,031,225.32	15.00	7.34	0.4805	1.0000	$2,898,026.03	$394,739.49

Remaining Life Depreciation Accrual

Account: PECO Common 3926 PA
Scenario: PECO Common Groups 2024
Dispersion: 15.00 - L2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$6,031,225.32	7.34	$224,069.85	3.715163%	13.620978%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($598,032.91)	0.50	($19,934.43)	3.333333%	
Total:	$6,031,225.32 *		$204,135.42	3.384643%	12.409184%
Average:	$5,732,208.87		$204,135.42	3.561200%	15.165870%
Grand Total:	$6,031,225.32 *		$204,135.42	3.384643%	12.409184%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3927 PA
Dispersion: 8.00 - L4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$4,224,204.73	8.00	7.50	0.9375	1.0000	$3,960,191.88	$528,025.59
2022	1.50	$1,448,573.64	8.00	6.50	0.8125	1.0000	$1,176,966.06	$181,071.71
2021	2.50	$5,222,906.86	8.00	5.50	0.6876	1.0000	$3,591,149.95	$652,863.36
2020	3.50	$2,101,106.06	8.00	4.52	0.5650	1.0000	$1,187,143.19	$262,638.26
2019	4.50	$10,476,557.91	8.00	3.61	0.4507	1.0000	$4,721,866.82	$1,309,569.74
2018	5.50	$4,451,531.94	8.00	2.79	0.3482	1.0000	$1,549,851.53	$556,441.49
2017	6.50	$1,995,253.94	8.00	2.11	0.2636	1.0000	$525,964.98	$249,406.74
		$29,920,135.08	8.00	4.47	0.5586	1.0000	$16,713,134.42	$3,740,016.89

Remaining Life Depreciation Accrual

Account: PECO Common 3927 PA
Scenario: PECO Common Groups 2024
Dispersion: 8.00 - L4

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$29,920,135.08	4.47	$3,728,943.92	12.462992%	22.377713%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($1,736,284.79)	0.50	($108,517.80)	6.250000%	
Total:	$29,920,135.08 *		$3,620,426.12	12.100300%	21.726488%
Average:	$29,051,992.69		$3,620,426.12	12.461886%	22.920605%
Grand Total:	$29,920,135.08 *		$3,620,426.12	12.100300%	21.726488%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3930 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$121,632.00	15.00	14.50	0.9667	1.0000	$117,577.60	$8,108.80
2021	2.50	$272,946.64	15.00	12.50	0.8333	1.0000	$227,455.53	$18,196.44
2019	4.50	$196,774.10	15.00	10.50	0.7000	1.0000	$137,741.87	$13,118.27
2018	5.50	$463,423.36	15.00	9.50	0.6333	1.0000	$293,501.46	$30,894.89
2017	6.50	$785.81	15.00	8.50	0.5667	1.0000	$445.29	$52.39
2016	7.50	$115,923.80	15.00	7.50	0.5000	1.0000	$57,961.90	$7,728.25
2015	8.50	$770.40	15.00	6.50	0.4333	1.0000	$333.84	$51.36
2014	9.50	$770.40	15.00	5.50	0.3667	1.0000	$282.48	$51.36
2013	10.50	$46,416.68	15.00	4.50	0.3000	1.0000	$13,925.00	$3,094.45
2011	12.50	$5,183.04	15.00	2.50	0.1667	1.0000	$863.84	$345.54
2010	13.50	$60,242.00	15.00	1.50	0.1000	1.0000	$6,024.20	$4,016.13
2009	14.50	$54,743.00	15.00	0.50	0.0333	1.0000	$1,824.77	$3,649.53
		$1,339,611.23	15.00	9.61	0.6404	1.0000	$857,937.79	$89,307.42

Remaining Life Depreciation Accrual

Account: PECO Common 3930 PA
Scenario: PECO Common Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,339,611.23	9.61	$100,461.91	7.499333%	10.409545%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($54,743.00)	0.50	($1,824.77)	3.333339%	
Total:	$1,339,611.23 *		$98,637.14	7.363117%	10.220468%
Average:	$1,312,239.73		$98,637.14	7.516701%	10.518797%
Grand Total:	$1,339,611.23 *		$98,637.14	7.363117%	10.220468%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3942 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2018	5.50	$952,765.21	15.00	9.50	0.6333	1.0000	$603,417.97	$63,517.68
2016	7.50	$2,088.50	15.00	7.50	0.5000	1.0000	$1,044.25	$139.23
2014	9.50	$55,267.65	15.00	5.50	0.3667	1.0000	$20,264.81	$3,684.51
		$1,010,121.36	15.00	9.28	0.6185	1.0000	$624,727.02	$67,341.42

Remaining Life Depreciation Accrual

Account: PECO Common 3942 PA
Scenario: PECO Common Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,010,121.36	9.28	$69,378.41	6.868324%	10.779336%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$1,010,121.36 *		$69,378.41	6.868324%	10.779336%
Average:	$1,010,121.36		$69,378.41	6.868324%	10.779336%
Grand Total:	$1,010,121.36 *		$69,378.41	6.868324%	10.779336%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3943 PA
Dispersion: 20.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$34,175.67	20.00	19.50	0.9750	1.0000	$33,321.28	$1,708.78
2022	1.50	$80,643.65	20.00	18.50	0.9250	1.0000	$74,595.38	$4,032.18
2021	2.50	$168,062.80	20.00	17.50	0.8750	1.0000	$147,054.95	$8,403.14
2020	3.50	$35,598.30	20.00	16.50	0.8250	1.0000	$29,368.60	$1,779.92
2019	4.50	$15,709.23	20.00	15.50	0.7750	1.0000	$12,174.65	$785.46
2018	5.50	$102,889.01	20.00	14.50	0.7250	1.0000	$74,594.53	$5,144.45
2017	6.50	$171,250.58	20.00	13.50	0.6750	1.0000	$115,594.14	$8,562.53
2016	7.50	$424,469.01	20.00	12.50	0.6250	1.0000	$265,293.13	$21,223.45
2015	8.50	$83,948.79	20.00	11.50	0.5750	1.0000	$48,270.55	$4,197.44
2014	9.50	$126,931.56	20.00	10.50	0.5250	1.0000	$66,639.07	$6,346.58
2013	10.50	$60,134.71	20.00	9.50	0.4750	1.0000	$28,563.99	$3,006.74
2012	11.50	$22,052.17	20.00	8.50	0.4250	1.0000	$9,372.17	$1,102.61
2011	12.50	$50,175.40	20.00	7.50	0.3750	1.0000	$18,815.78	$2,508.77
2010	13.50	$73,469.80	20.00	6.50	0.3250	1.0000	$23,877.69	$3,673.49
2008	15.50	$12,963.09	20.00	4.50	0.2250	1.0000	$2,916.70	$648.15
2007	16.50	$21,453.01	20.00	3.50	0.1750	1.0000	$3,754.28	$1,072.65
2006	17.50	$3,478.87	20.00	2.50	0.1250	1.0000	$434.86	$173.94
2004	19.50	$54,167.87	20.00	0.50	0.0250	1.0000	$1,354.20	$2,708.39
		$1,541,573.52	20.00	12.40	0.6201	1.0000	$955,995.93	$77,078.68

Remaining Life Depreciation Accrual

Account: PECO Common 3943 PA
Scenario: PECO Common Groups 2024
Dispersion: 20.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,541,573.52	12.40	$76,247.62	4.946090%	8.062657%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($54,167.87)	0.50	($1,354.20)	2.500006%	
Total:	$1,541,573.52 *		$74,893.42	4.858245%	7.919460%
Average:	$1,514,489.59		$74,893.42	4.945126%	8.152956%
Grand Total:	$1,541,573.52 *		$74,893.42	4.858245%	7.919460%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3961 PA
Dispersion: 12.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2002	21.50	$93,979.86	12.00	0.90	0.0753	1.0000	$7,074.20	$7,831.66
1998	25.50	$35,800.78	12.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	37.50	$5,472.23	12.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	42.50	$6,017.00	12.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	43.50	$3,955.00	12.00	0.00	0.0000	0.0000	$0.00	$0.00
1977	46.50	$11,826.57	12.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	50.50	$28,014.86	12.00	0.00	0.0000	0.0000	$0.00	$0.00
		$185,066.30	12.00	0.90	0.0382	1.0000	$7,074.20	$7,831.66

Remaining Life Depreciation Accrual

Account: PECO Common 3961 PA
Scenario: PECO Common Groups 2024
Dispersion: 12.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$185,066.30	0.90	$101.58	0.054888%	100.000000%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($60,015.78)	0.50	($2,500.66)	4.166671%	
Total:	$185,066.30 *		($2,399.08)	-1.296335%	2361.764127%
Average:	$155,058.41		($2,399.08)	-1.547210%	8.021986%
Grand Total:	$185,066.30 *		($2,399.08)	-1.296335%	2361.764127%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3970 PA
Dispersion: 20.00 - L3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2023	0.50	$12,675,460.89	20.00	19.50	0.9750	1.0000	$12,358,574.37	$633,773.04
2022	1.50	$13,546,160.99	20.00	18.50	0.9250	1.0000	$12,530,198.92	$677,308.05
2021	2.50	$3,484,206.74	20.00	17.50	0.8750	1.0000	$3,048,774.97	$174,210.34
2020	3.50	$32,862,198.64	20.00	16.51	0.8253	1.0000	$27,121,422.64	$1,643,109.93
2019	4.50	$17,853,340.73	20.00	15.52	0.7762	1.0000	$13,857,356.04	$892,667.04
2018	5.50	$18,280,188.44	20.00	14.56	0.7279	1.0000	$13,306,288.56	$914,009.42
2017	6.50	$221,177.09	20.00	13.61	0.6807	1.0000	$150,557.28	$11,058.85
2016	7.50	$422,148.93	20.00	12.69	0.6347	1.0000	$267,944.17	$21,107.45
2015	8.50	$1,444,889.14	20.00	11.80	0.5900	1.0000	$852,542.83	$72,244.46
2014	9.50	$1,088,927.83	20.00	10.94	0.5470	1.0000	$595,600.67	$54,446.39
2013	10.50	$34,614.16	20.00	10.12	0.5060	1.0000	$17,513.64	$1,730.71
2012	11.50	$745,044.85	20.00	9.36	0.4679	1.0000	$348,607.84	$37,252.24
2008	15.50	$1,390,836.04	20.00	7.12	0.3559	1.0000	$494,999.39	$69,541.80
2007	16.50	$6,682,064.26	20.00	6.78	0.3388	1.0000	$2,263,627.04	$334,103.21
2006	17.50	$7,909,519.60	20.00	6.50	0.3251	1.0000	$2,571,593.96	$395,475.98
2005	18.50	$50,000.00	20.00	6.28	0.3142	1.0000	$15,709.60	$2,500.00
2003	20.50	$614,915.20	20.00	5.93	0.2966	1.0000	$182,356.28	$30,745.76
2002	21.50	$50,892.16	20.00	5.77	0.2883	1.0000	$14,670.05	$2,544.61
2001	22.50	$122,375.76	20.00	5.58	0.2792	1.0000	$34,171.14	$6,118.79
1999	24.50	$1,031,170.51	20.00	5.16	0.2581	1.0000	$266,175.61	$51,558.53
1998	25.50	$7,398,704.24	20.00	4.92	0.2461	1.0000	$1,820,533.26	$369,935.21
1997	26.50	$794,445.38	20.00	4.67	0.2335	1.0000	$185,541.59	$39,722.27
		$128,703,281.58	20.00	14.34	0.7172	1.0000	$92,304,759.85	$6,435,164.08

Remaining Life Depreciation Accrual

Account: PECO Common 3970 PA
Scenario: PECO Common Groups 2024
Dispersion: 20.00 - L3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$128,703,281.58	14.34	$6,279,780.15	4.879270%	6.971649%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($3,396,767.30)	0.50	($84,919.18)	2.500000%	
Total:	$128,703,281.58 *		$6,194,860.97	4.813289%	6.877374%
Average:	$127,004,897.93		$6,194,860.97	4.877655%	7.009539%
Grand Total:	$128,703,281.58 *		$6,194,860.97	4.813289%	6.877374%

* Excluding 2024 Retirements

Generation Arrangement Report

PECO Common Groups 2024

Account: PECO Common 3980 PA
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2024

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2017	6.50	$57,233.54	15.00	8.50	0.5667	1.0000	$32,432.34	$3,815.57
2015	8.50	$16,773.27	15.00	6.50	0.4333	1.0000	$7,268.42	$1,118.22
2014	9.50	$497,037.52	15.00	5.50	0.3667	1.0000	$182,247.09	$33,135.83
2012	11.50	$67,989.42	15.00	3.50	0.2333	1.0000	$15,864.20	$4,532.63
2011	12.50	$22,622.02	15.00	2.50	0.1667	1.0000	$3,770.34	$1,508.13
2010	13.50	$511,435.53	15.00	1.50	0.1000	1.0000	$51,143.55	$34,095.70
2009	14.50	$18,269.07	15.00	0.50	0.0333	1.0000	$608.97	$1,217.94
		$1,191,360.37	15.00	3.69	0.2462	1.0000	$293,334.90	$79,424.02

Remaining Life Depreciation Accrual

Account: PECO Common 3980 PA
Scenario: PECO Common Groups 2024
Dispersion: 15.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2024

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2024 Additions	$1,191,360.37	3.69	$92,455.40	7.760490%	27.076225%
2024 Additions	$0.00	0.00	$0.00	0.000000%	
2024 Retirements	($18,269.07)	0.50	($608.97)	3.333339%	
Total:	$1,191,360.37 *		$91,846.43	7.709374%	26.897884%
Average:	$1,182,225.84		$91,846.43	7.768941%	27.637211%
Grand Total:	$1,191,360.37 *		$91,846.43	7.709374%	26.897884%

* Excluding 2024 Retirements

PECO Exhibit CF-2:

Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2024

PECO Exhibit CF-2

Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2024

Summary –

This exhibit is based on the results of the 2018 Depreciation Study and updated to reflect the estimated original cost of PECO's electric and common plant in service at December 31, 2024.

Estimated Annual Depreciation Accruals Related to Utility Plant In Service for 2024

Utility Account	2018 Service Life Study - Average Service Life	2018 Service Life Study - Dispersion Curve	2024 Depreciation Rate	Original Cost of Gross Plant - January 1, 2024	2024 Estimated Plant Additions	2024 Estimated Plant Retirements	Estimated Original Cost of Gross Plant - December 31, 2024	Accumulated Book Reserve - January 1, 2024	2024 Estimated Annual Depreciation Accrual	2024 Estimated Plant Retirements	2024 - Estimated Cost of (Removal) / Salvage	Estimated Accumulated Book Reserve - December 31, 2024	Estimated Depreciable Plant Net Book Value - December 31, 2024
361 Structures and Improvements	50	R2.5	2.61%	208,819,319	23,939,824	(668,551)	232,090,592	46,767,489	4,491,407	(668,551)	(1,110,165)	49,480,180	182,610,412
362 Station Equipment	53	R3	3.01%	1,247,092,867	81,716,025	(3,172,113)	1,325,636,779	502,906,513	22,950,608	(3,172,113)	(5,745,989)	516,939,019	808,697,760
364 Poles, Towers and Fixtures	53	R2	2.35%	1,161,297,653	185,692,527	(20,980,132)	1,326,010,048	97,703,840	27,181,572	(20,980,132)	(16,668,930)	87,236,350	1,238,773,698
365 Overhead Conudctors & Devices	52	R2.5	2.45%	1,948,620,832	232,636,844	(16,652,461)	2,164,605,215	292,179,557	43,196,683	(16,652,461)	(19,073,471)	299,650,308	1,864,954,907
366 Underground Conduit	70	R4	1.87%	765,407,398	140,256,767	(835,159)	904,829,006	180,286,549	12,642,646	(835,159)	(4,267,467)	187,826,569	717,002,437
367 Underground Conductors & Devices	54	S0.5	2.33%	1,801,734,416	257,973,460	(17,857,555)	2,041,850,321	194,984,165	40,239,770	(17,857,555)	(20,169,407)	197,196,973	1,844,653,348
368 Line Transformers	47	R1.5	2.92%	774,629,125	93,872,499	(16,467,875)	852,033,749	177,956,968	18,403,285	(16,467,875)	(896,536)	178,995,842	673,037,907
369.1 Services - Aerial	53	R4	2.88%	189,424,658	12,898,730	(88,032)	202,235,356	66,590,461	3,658,868	(88,032)	(496,123)	69,665,174	132,570,182
369.2 Services - Underground	55	R3	3.37%	278,093,550	5,240,997	(110,077)	283,224,470	130,589,272	4,958,811	(110,077)	(211,488)	135,226,518	147,997,952
370.1 Meter Transformers	35	R2	3.28%	5,355,832	1,078,424	-	6,434,256	827,149	160,276	-	-	987,425	5,446,831
370.2 Smart Meters	15	S2	14.06%	341,661,056	10,154,013	(196,189)	351,618,880	196,184,246	19,320,108	(196,189)	(206,850)	215,101,315	136,517,565
371 Installs on Customers' Premises	36	R4	8.34%	1,030,123	-	-	1,030,123	975,618	4,375	-	-	979,993	50,130
371.1 Installs on Customers' Premises - DLC Switches **(Note A)**	15	S2	20.28%	12,742,260	-	-	12,742,260	9,683,625	565,730	-	-	10,249,355	2,492,905
373 Street Lighting and Signal Systems	24	L0	Various	66,272,522	5,776,535	(714,959)	71,334,098	33,964,668	1,845,890	(714,959)	(113,517)	34,982,082	36,352,016
374 Asset Retirement costs **(Note B)**	N/A	N/A	N/A	2,693,062	-	(170,084)	2,522,978	2,140,683	74,941	(170,084)	-	2,045,540	477,438
Distribution Subtotal				**8,804,874,673**	**1,051,236,645**	**(77,913,187)**	**9,778,198,131**	**1,933,740,803**	**199,694,970**	**(77,913,187)**	**(68,959,943)**	**1,986,562,643**	**7,791,635,488**
Intangible Plant Allocated to Distribution **(Note C)**				135,646,068	44,929,214	(54,112,792)	126,462,490	93,369,082	15,611,410	(54,112,792)	-	54,867,700	71,594,790
General Plant Allocated to Distribution **(Note D)**				280,951,092	8,524,977	(9,222,321)	280,253,748	111,905,093	18,137,007	(9,222,321)	(716,508)	120,103,271	160,150,477
Common Plant Allocated to Distribution **(Note E)**				742,401,391	176,879,677	(121,043,116)	798,237,952	312,110,065	60,466,439	(121,043,116)	(2,848,610)	248,684,778	549,553,174
Depreciable Total				**9,963,873,224**	**1,281,570,513**	**(262,291,416)**	**10,983,152,321**	**2,451,125,043**	**293,909,826**	**(262,291,416)**	**(72,525,061)**	**2,410,218,392**	**8,572,933,930**

Fleet Depreciation **(Note F)**	(10,514,781)
ARC Amortization **(Note B)**	(286,591)
Act 129 **(Note G)**	(565,730)
Regulatory Assets **(Note H)**	(393,204)
Adjusted 2024 estimated annual depreciation accrual	**282,149,520**
	Note I

Notes:

Note A: Utility Account 371.1 was not included in the 2018 study and will continue to depreciate over the 2013 average service life.

Note B: Asset Retirement Costs (ARC) are depreciable plant, but the ARC depreciation expense is not included in the revenue requirements calculation and not included in the claim for the current proceeding.

Note C: The Intangible Plant allocated to Electric Distribution is individually depreciated based on the service lives estimated at the time the plant is placed into service. The amortization rates for Intangible Plant are weighted based on the relative amount of underlying plant booked to the Intangible Plant accounts.

Note D: The General Plant allocated to Electric Distribution relates to various General Plant utility accounts identified in the 2018 Depreciation Study; the depreciation rates are calculated the same as Electric Distribution Plant. The General Plant amounts are allocated to Electric Distribution plant based on a labor allocation methodology as explained in Mr. Trzaska's testimony (PECO Statement No. 3).

Note E: The Common Plant allocated to Electric Distribution relates to various Common Plant utility accounts identified in the 2018 Depreciation Study; the depreciation rates are calculated the same as Electric Distribution Plant. The Common Plant amounts are allocated to Electric plant based on the Common Allocation Factor determined each year and further allocated to Electric Distribution plant based on a labor allocation methodology.

Note F: Included in the 2024 Estimated Annual Depreciation Accrual column for the Common Plant allocated to Distribution row is $10.5 million relating to PECO Fleet depreciation. PECO Fleet depreciation is reversed from depreciation expense and redistributed to both capital and expense accounts/projects. As a result, a $10.5 million credit is shown for Fleet depreciation expense. The amount of Fleet depreciation that is capitalized to Electric Distribution capital projects is included in the 2024 Estimated Plant Additions column and related depreciation is in the 2024 Estimated Annual Depreciation Accrual column.

Note G: ACT 129 costs for Direct Load Control (DLC) switches were fully recovered in 2013 and are not included in the claim for the current proceeding.

Note H: Included in the 2024 Estimated Annual Depreciation Accrual is $0.4 million relating to PECO Regulatory Asset amortization. Regulatory Asset amortization expense is charged to a Regulatory Asset.

Note I: Agrees to Electric Distribution depreciation expense included in the revenue requirements calculation in Exhibit MJT-2, Schedule D-17, Column 13 Depr on Existing Assets + Adds (Function), Row 143

PECO Exhibit CF-3:

Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2025

PECO Exhibit CF-3

Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2025

Summary –

This exhibit is based on the results of the 2018 Depreciation Study and updated to reflect the estimated original cost of PECO's electric and common plant in service at December 31, 2025.

Estimated Annual Depreciation Accruals Related to Utility Plant In Service for 2025

Utility Account	2018 Service Life Study - Average Service Life	2018 Service Life Study - Dispersion Curve	2025 Depreciation Rate	Original Cost of Gross Plant - January 1, 2025	2025 Estimated Plant Additions	2025 Estimated Plant Retirements	Estimated Original Cost of Gross Plant - December 31, 2025	Accumulated Book Reserve - January 1, 2025	2025 Estimated Annual Depreciation Accrual	2025 Estimated Plant Retirements	2025 - Estimated Cost of (Removal) / Salvage	Estimated Accumulated Book Reserve - December 31, 2025	Estimated Depreciable Plant Net Book Value - December 31, 2025
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Distribution Subtotal				**9,778,198,131**	**1,061,087,725**	**(77,913,187)**	**10,761,372,669**	**1,986,562,643**	**228,842,766**	**(77,913,187)**	**(68,959,943)**	**2,068,532,279**	**8,692,840,390**
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Depreciable Total				**10,983,152,321**	**1,171,848,998**	**(125,005,896)**	**12,029,995,423**	**2,410,218,392**	**332,117,179**	**(125,005,896)**	**(72,525,061)**	**2,544,804,614**	**9,485,190,809**

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Notes:

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Gannett Fleming

*Excellence Delivered **As Promised***

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PECO ENERGY COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

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SUMMARY OF ORIGINAL COST, PROPOSED ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST AS OF DECEMBER 31, 2018	ACCRUAL RATE	ACCRUAL AMOUNT
(1)	(2)	(3)=(4)/(2)	(4)
ELECTRIC PLANT			
Distribution Plant	1	1	1
General Plant	01		1
Total Electric Plant	**6,534,488,548**	**2.33**	**152,570,017**
COMMON PLANT			
General Plant	1		011 0
Total Common Plant	**512,723,577**	**4.68**	**24,011,209**
Total	**7,047,212,125**	**2.51**	**176,581,226**

PART I. INTRODUCTION

PECO ENERGY COMPANY

DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation studies for PECO Energy Company (PECO) to determine the annual depreciation accruals and rates and amounts for book reserves allocable to the original cost of electric and common plant as of December 31, 2018. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and procedures which underlie the recommended annual depreciation accruals related to electric and common plant in service as of December 31, 2018.

The service life estimates resulting from the studies were based on information which incorporated analyses of historical and current retirement data and recorded through 2018 a review of Company practices and outlook as the relate to current operations and retirements and considerations of current practice in the electric industry including knowledge of service life estimates used for other electric companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the scope of the report and the basis of the studies. Part II, Estimation of Survivor Curves, sets forth descriptions of the considerations and the methods used in the service life studies. Part III, Service Life Considerations, sets forth the factors and judgments utilized in the average service life analyses. Part IV, Net Salvage Considerations, sets forth analyses of the methods used by PECO for the recovery of net salvage. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of studies, sets forth comparisons by depreciable group of

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BASIS OF THE STUDY

Depreciation

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Service Life Estimates

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PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The estimation of average service life and the allocation of depreciation to the various years of life are usually made by the use of survivor curves. The estimation of survivor curves is discussed below.

SURVIVOR CURVES

The life of an average service life for a property group is based on the assumption that the various units in the group have different lives. The average life can be obtained by determining the separate lives of each of the units or by constructing a survivor curve by plotting the number of units which survive at various ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve the average life of the group, the remaining life expectancy, the probable life and the frequency curve can be estimated. In Figure 1 a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by estimating the area under the survivor curve from age zero to the maximum age and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be estimated by obtaining the area under the curve from the observation age to the maximum age and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 40 is equal to the crosshatched area under the survivor curve divided by percent surviving at age 40. The probable life at any age is determined by adding the age and remaining life. If the probable life of the property is estimated for each year of age, the probable life curve shown in the chart can be determined. The frequency curve represents the number of units retired in each age interval. It is derived by obtaining the difference between the amounts of property surviving at the beginning and at the end of each interval.

This study incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of curvilinear and of the development of curves using the retirement rate method is presented below.

Iowa Type Curves

The range of curvilinear characteristics assumed experienced by industrial properties is represented by a family of generalized curvilinear curves known as the Iowa type curves. There are four families in the Iowa state curves labeled in accordance with the location of the mode of the retirements or the portion of the frequency curve with the highest level of retirements in relation to the average life and the relative height of the mode. The left moded curves represented in Figure are those in which the greatest frequency of retirements occurs to the left of or prior to average service life. The symmetrical moded curves represented in Figure are those in which the greatest frequency of retirements occurs at average service life. The right moded curves represented in Figure are those in which the greatest frequency occurs to the right of or after average service life. The origin moded curves represented in Figure are those in which the greatest frequency of retirements occurs at the origin or immediately after age zero. The letter designation of each family of curves L, S or R represents the location of the mode of the associated frequency curve with respect to the average service life. The number represents the relative height of the mode of the frequency curve within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study in which resulted in the classification of property curvilinear characteristics into 1 the curves

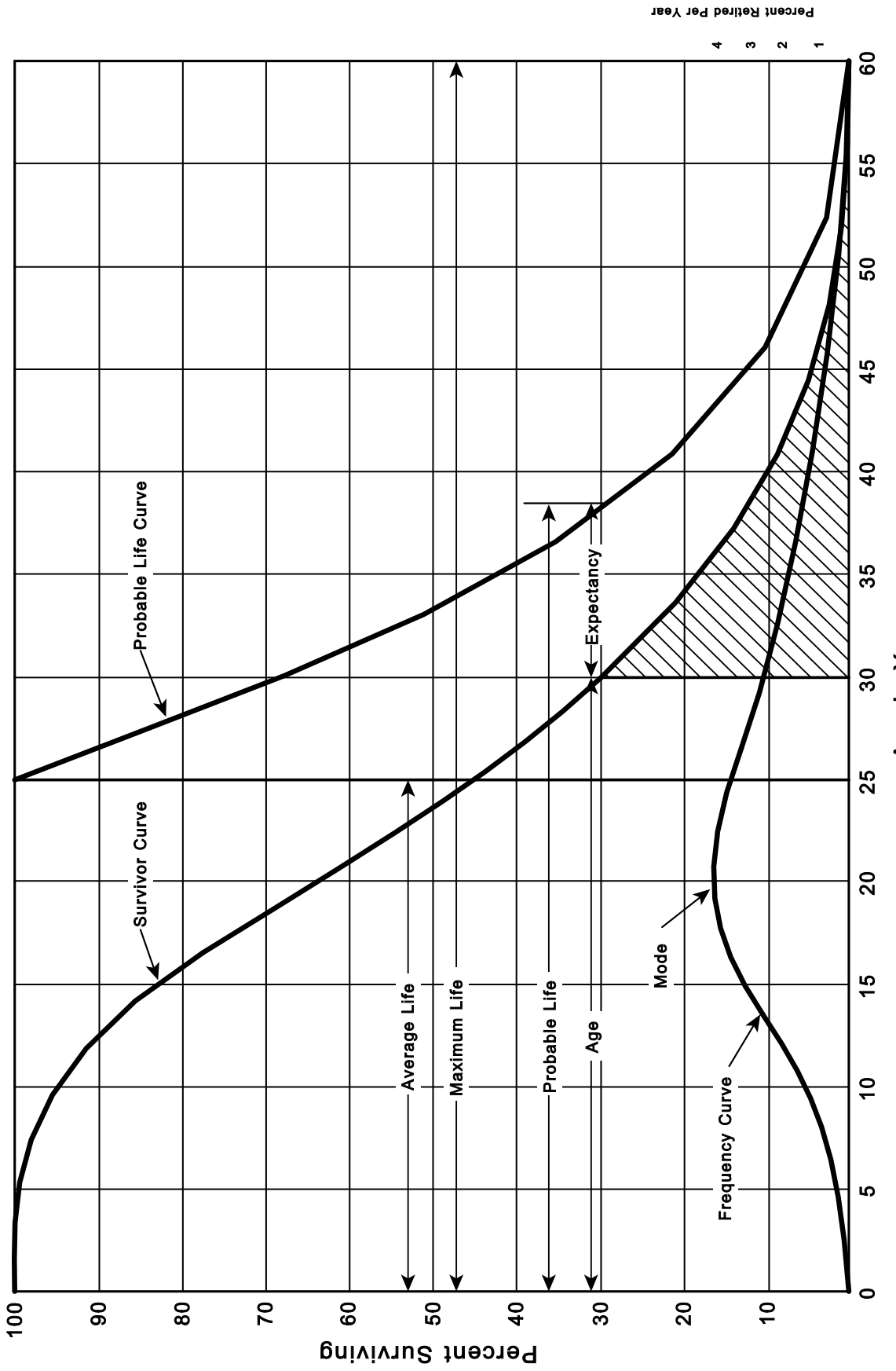

Figure 1. A Typical Survivor Curve and Derived Curves

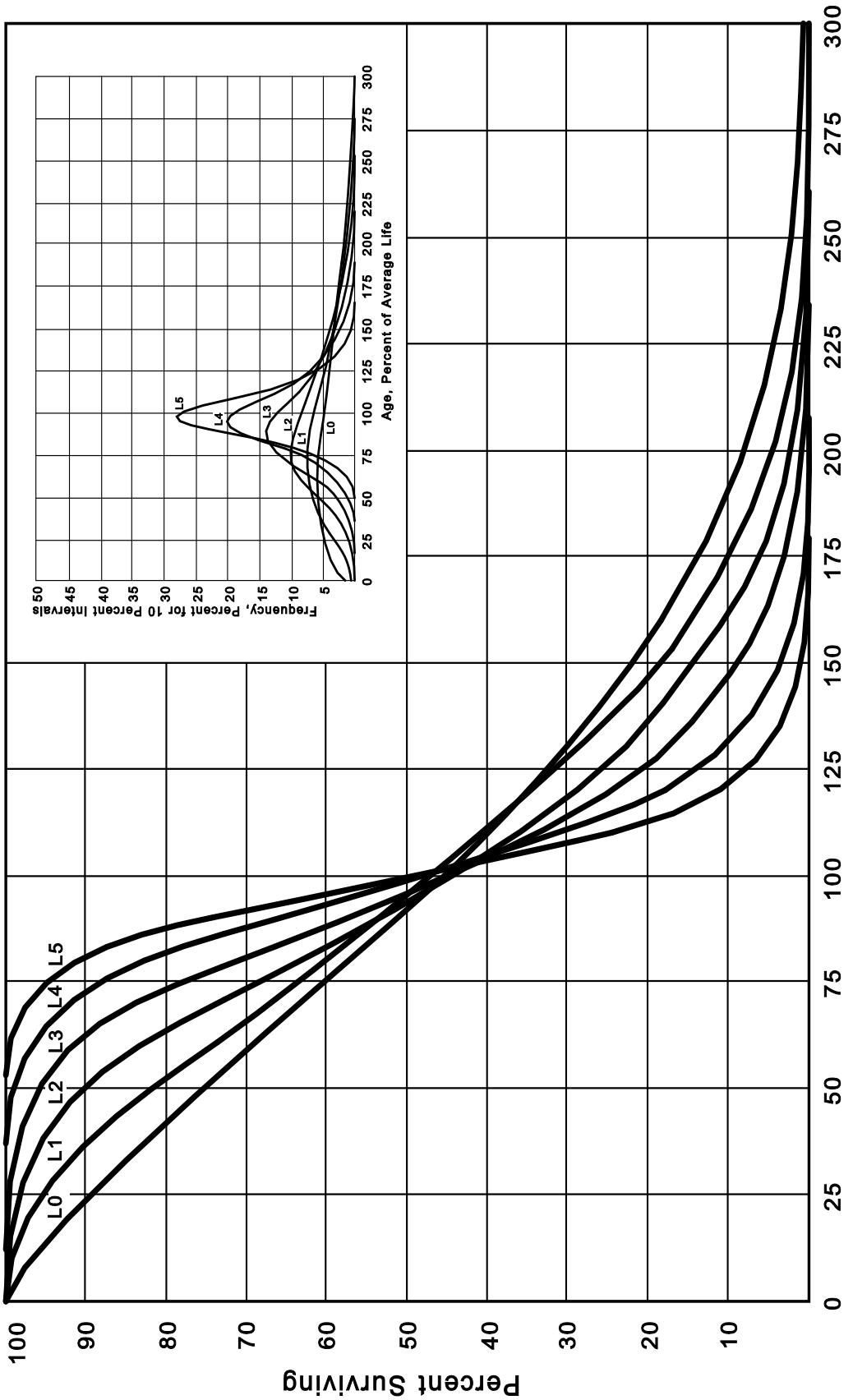

Figure 2. Left Modal or "L" Iowa Type Survivor Curves

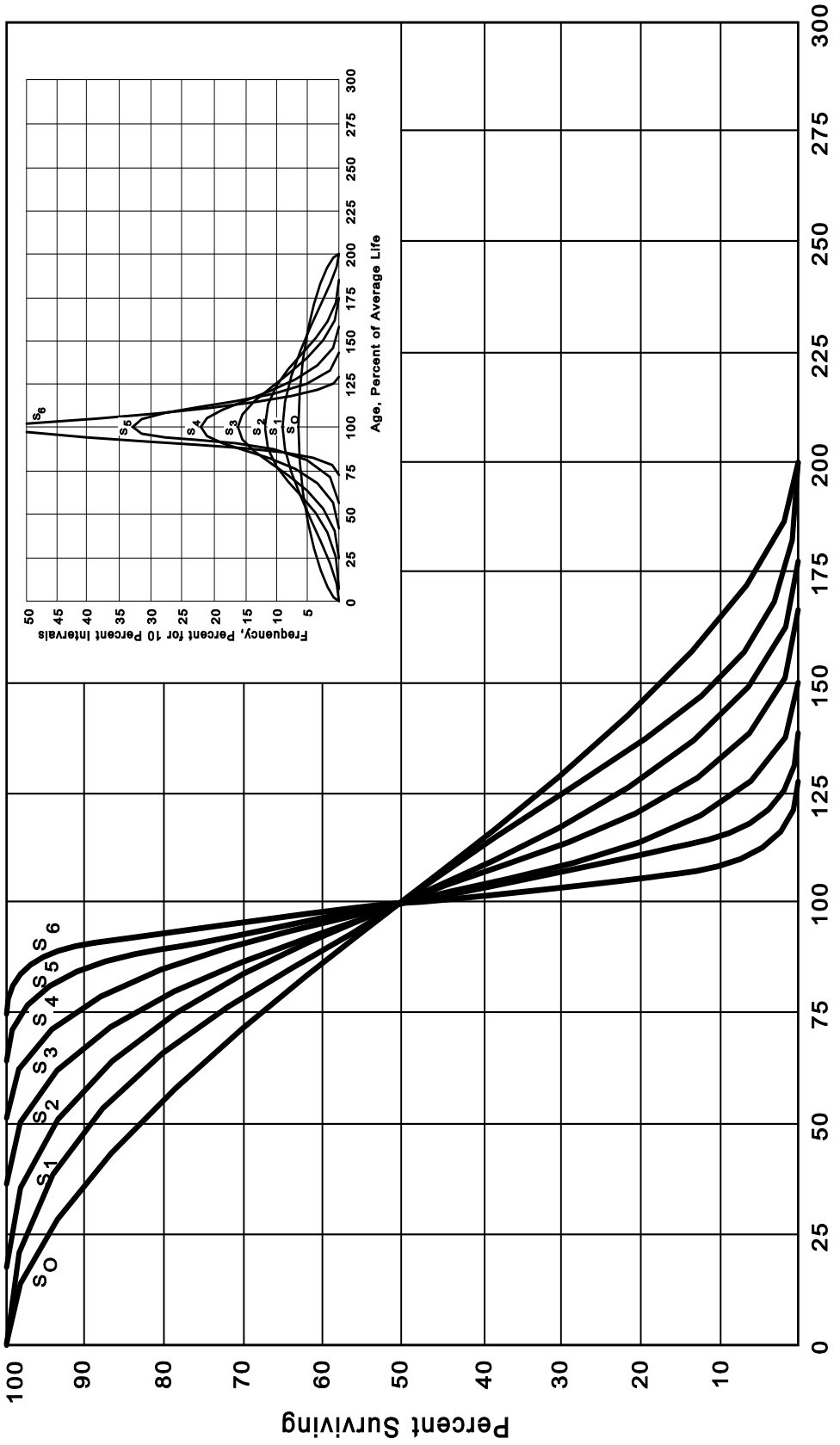

Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

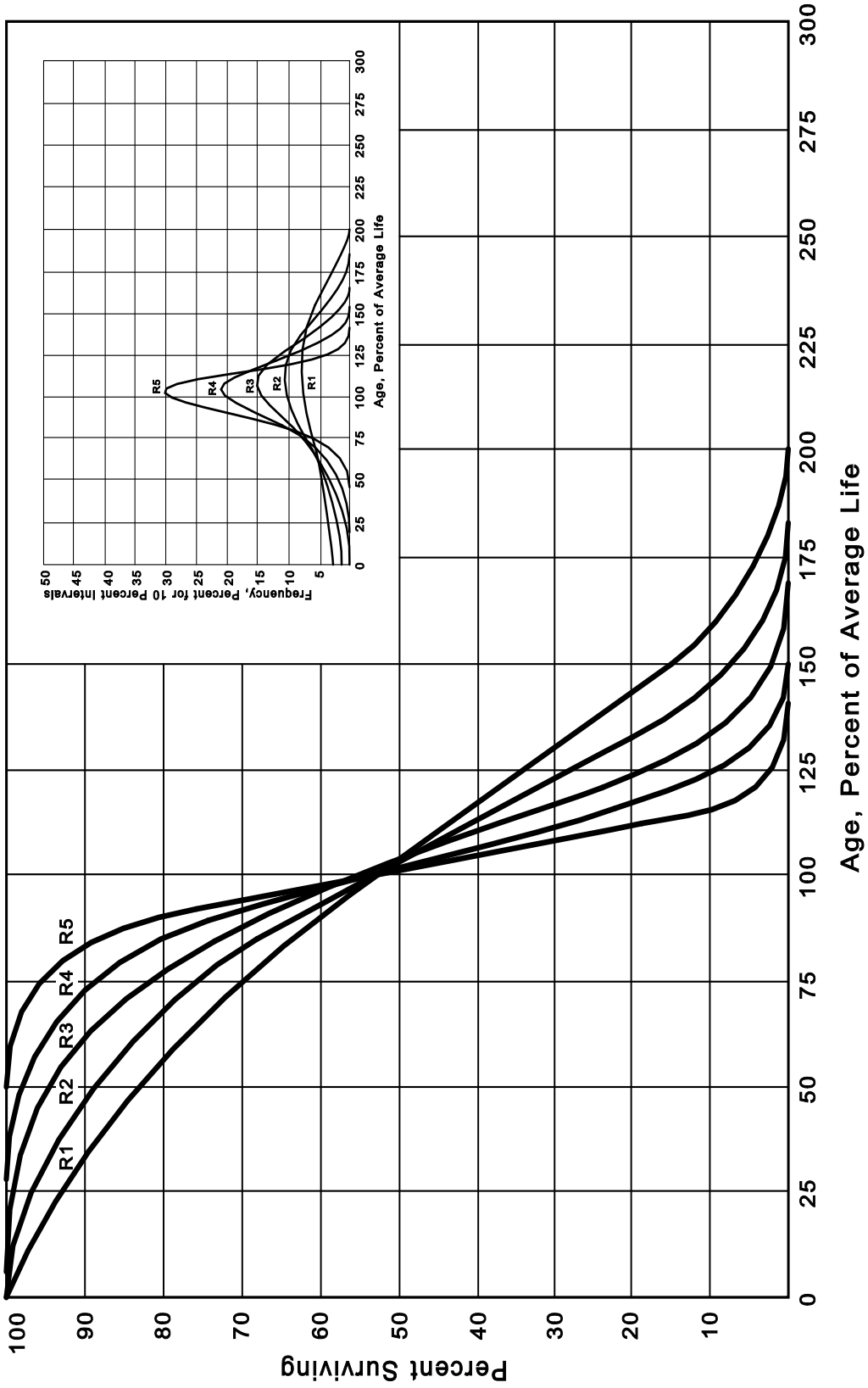

Figure 4. Right Modal or "R" Iowa Type Survivor Curves

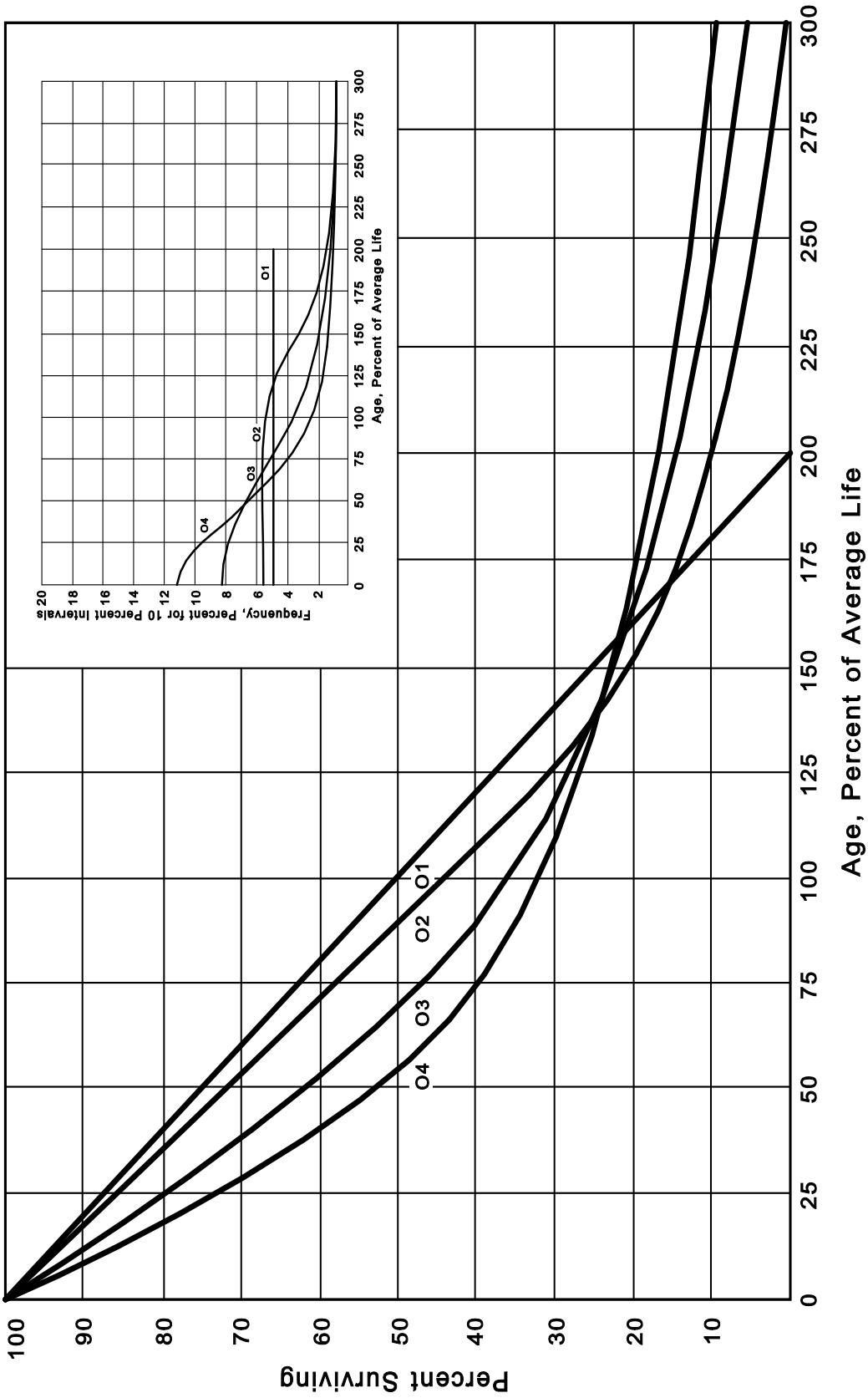

Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

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Retirement Rate Method of Analysis

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Schedules of Annual Transactions in Plant Records

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In addition to other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credited to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements but are used in determining the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The determination of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in schedule on page II-14. The starting plant at the beginning of each year from 2000 through 2018 is recorded by year in the portion of the table headed "Plant at Beginning of Year." The plant amount entered in each column is the amount of net plant added to the group during the year. The amounts entered in schedule 1 for each successive year following the beginning base or additions are obtained by adding or subtracting the net entries shown on schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfer-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred and the sales and transfer-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. The amounts of plant shown at the beginning of each year are the amounts of plant from each successive year considered to be exposed to retirement at the beginning of each successive transaction year. For example the exposures for the interpolation year 2018 are illustrated in the following manner.

Exposure at age 0	plus amount of additions	1,000
Exposure at age 1	1,000 - 100	900
Exposure at age 2	900 - 200	700
Exposure at age 3	700 - 300 - 100	300
Exposure at age 4	300 - 200	100

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[a]Additions during the year

For the entire experience band 2000-2018, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval as described above. For example, the figure of 1,000,000 shown as the total exposures at the beginning of age interval 2-3 is obtained by summing:

2,000 + 5,000 + 10,000 + 15,000 + 20,000 + 25,000 + 30,000 + 35,000 + 40,000 + 50,000 + 60,000 + 70,000 + 80,000 + 90,000 + 100,000 + 110,000 + 120,000 + 130,000 + 140,000 + 150,000 + 160,000 + 170,000 + 180,000 + 190,000 + 200,000 + 210,000 + 220,000 + 230,000 + 240,000 + 250,000 + 260,000 + 270,000 + 280,000 + 290,000 + 300,000 + 310,000 + 320,000 + 330,000 + 340,000 + 350,000 + 360,000 + 370,000 + 380,000 + 390,000 + 400,000 + 410,000 + 420,000 + 430,000 + 440,000 + 450,000 + 460,000 + 470,000 + 480,000 + 490,000 + 500,000 + 510,000 + 520,000 + 530,000 + 540,000 + 550,000 + 560,000 + 570,000 + 580,000 + 590,000 + 600,000 + 610,000 + 620,000 + 630,000 + 640,000 + 650,000 + 660,000 + 670,000 + 680,000 + 690,000 + 700,000 + 710,000 + 720,000 + 730,000 + 740,000 + 750,000 + 760,000 + 770,000 + 780,000 + 790,000 + 800,000 + 810,000 + 820,000 + 830,000 + 840,000 + 850,000 + 860,000 + 870,000 + 880,000 + 890,000 + 900,000 + 910,000 + 920,000 + 930,000 + 940,000 + 950,000 + 960,000 + 970,000 + 980,000 + 990,000 + 1,000,000

Original Life Table

The original life table illustrated in Exhibit II, Page II-1, is developed from the total shown on the Exhibit of retirements and exposures in Exhibit 1 and is presented in reverse sequence. The exposures at the beginning of the age intervals are obtained from the corresponding age intervals of the exposure Exhibit and the retirements during the age intervals are obtained from the corresponding age intervals of the retirement Exhibit. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio in the line for the retirement ratio for that age interval. The mathematical relationship used to determine the percent surviving at age x are as follows:

Percent surviving at age x	=	l(x)
Exposures at age x	=	Exhibit 1
Retirements from age x to x+1	=	Exhibit 1
Retirement Ratio	=	Exhibit 1 ÷ Exhibit 1	=	r(x)
Survivor Ratio	=	1.000 - r(x)	=	s(x)
Percent surviving at age x+1	=	l(x) x s(x)	=	l(x+1)

The total of the exposures and retirements for the experience band and are shown for the purpose of checking with the respective total in Exhibit 1 and . The ratio of the total retirements to the total exposures other than for each age interval in each age

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Smoothing the Original Survivor Curve

The □□oothi□g of the origi□a□□r□i□or □□r□e e□□i□ate□ a□□ irreg□□aritie□ a□d □er□e□ a□ the ba□i□ for the □re□i□i□ar□ extra□o□atio□ to □ero □er□e□t □□r□i□g of the origi□a□□t□b □□r□e□ E□e□ if the origi□a□□□r□i□or □□r□e i□ □o□ □□ete fro□ 100□ to □ero □er□e□t□it i□ de□irab□e to e□□i□ate a□□ irreg□□aritie□□a□there i□ □ti□□a□ extra□o□atio□ for the □i□tage□ □hi□h ha□e □ot □et □□ed to the age at □hi□h the □□r□e rea□he□ □ero □er□e□t□ I□ thi□ □t□d□□the □□oothi□g of the origi□a□□□r□e □ith e□tab□□hed t□□e □□r□e□ □a□ □□ed to e□□i□ate irreg□□aritie□ i□ the origi□a□□□r□e□

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FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

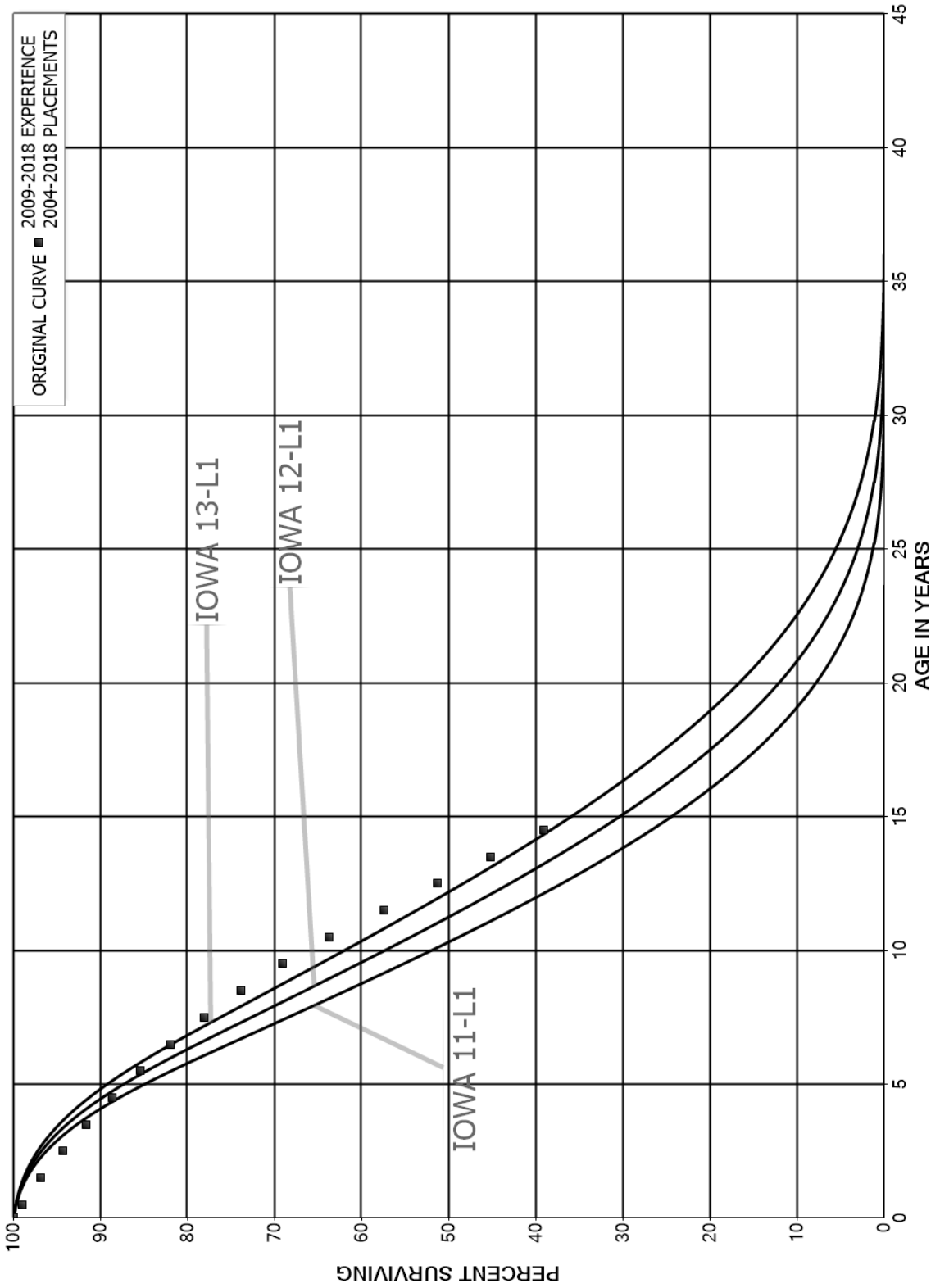


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

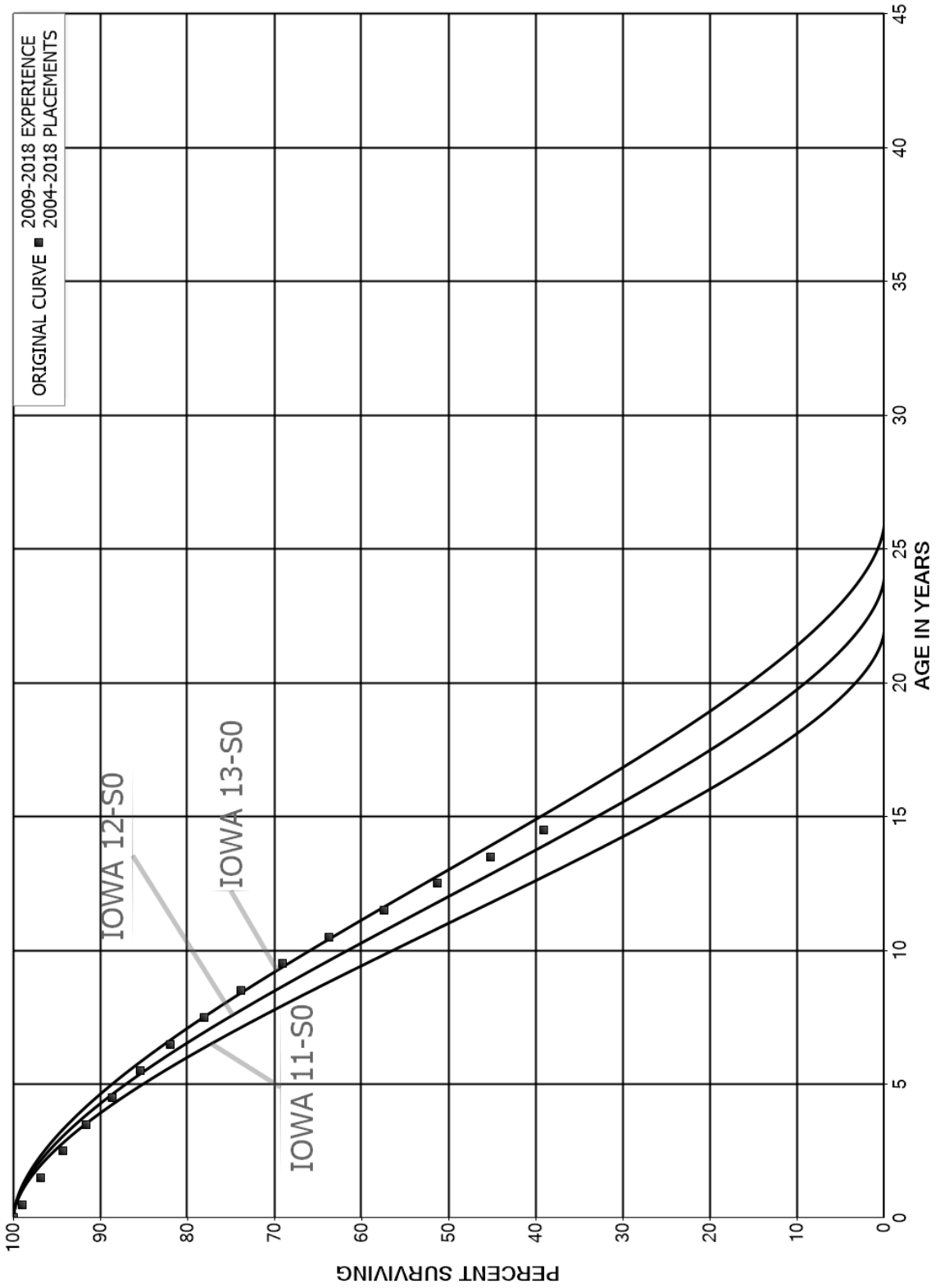


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

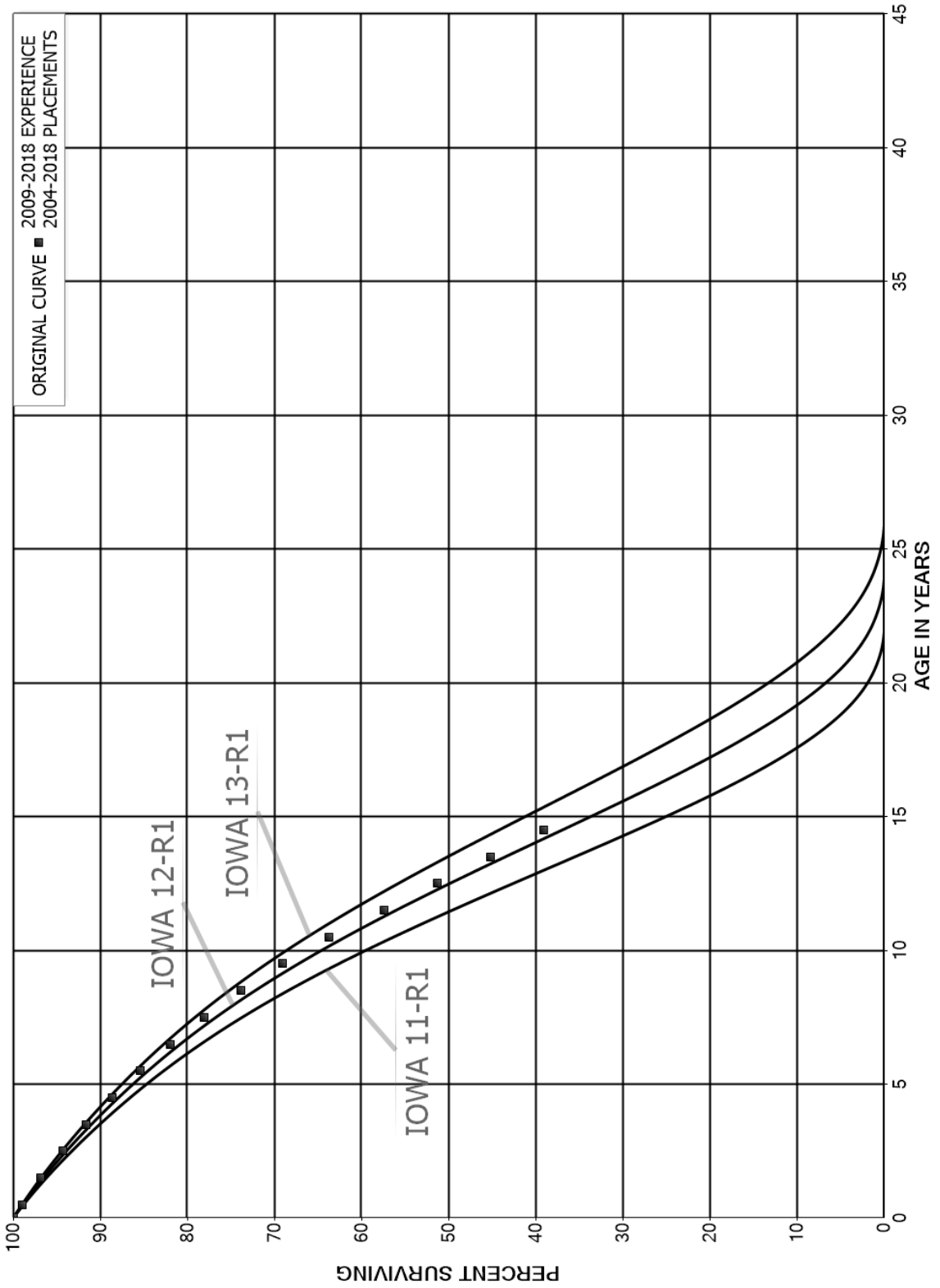
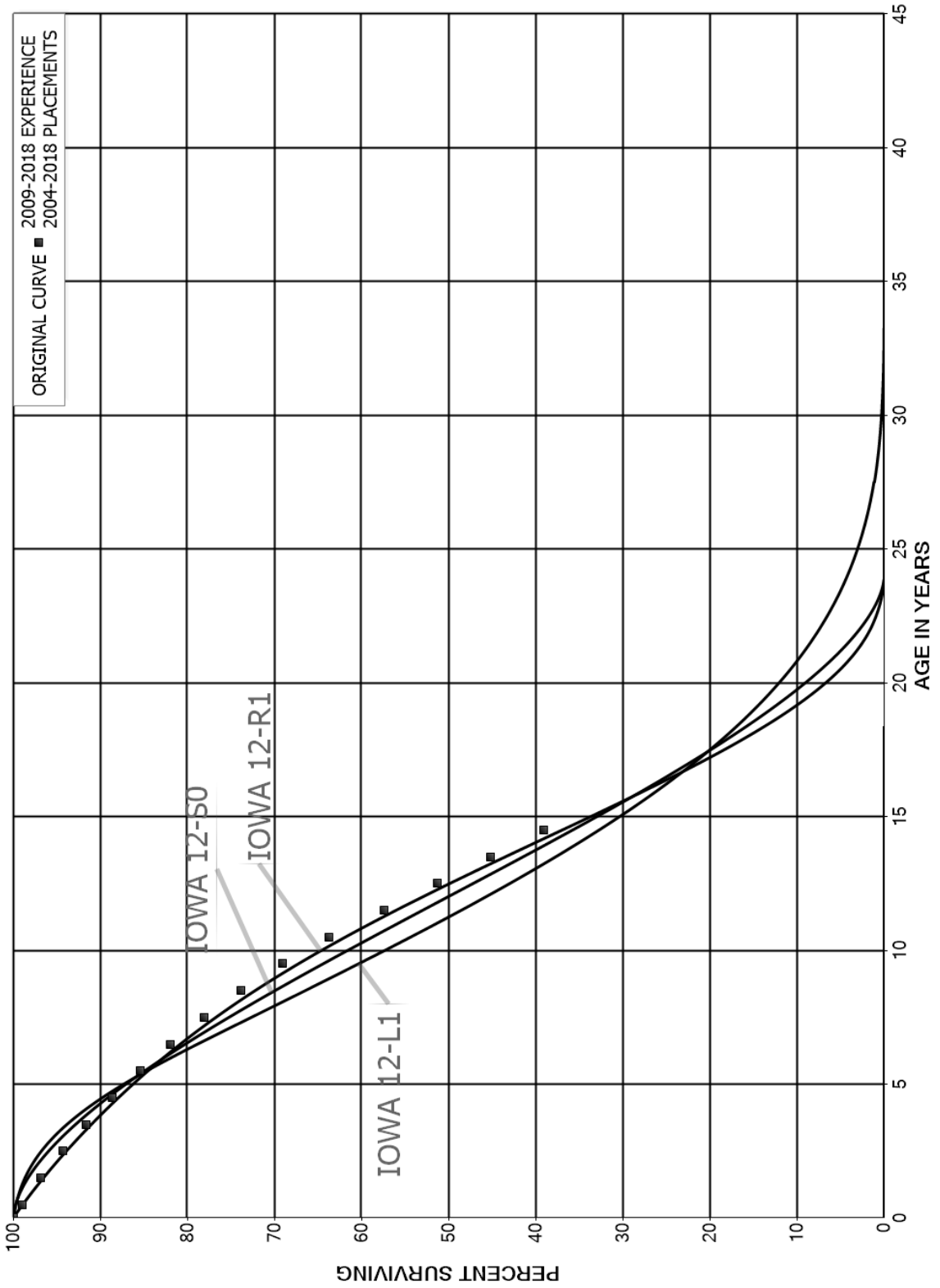


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

In order to be familiar with the operation of the Company and observe representative portions of the plant a field trip was conducted for the study group engineering understanding of the function of the plant and information with respect to the reasons for plant retirement and the expected future average of retirement are obtained during field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during the most recent field trips.

September 2010
- Bernice Service Center
- Home Distribution Substation
- Creamer Distribution Substation
- West Distribution Substation

September 2014
- Plymouth Service Center
- Plymouth Transmission Substation
- Plymouth Distribution Substation

September 2014
- PECO Energy Headquarters Building – 2301 Market Street

LIFE ANALYSIS

The retirement rate method of life analysis is an actuarial method of determining prior years by averaging the average rates at which property is retired from each depreciable group. The method involves the analysis of historical retirements of property of various ages in relation to the property exposed to retirement at those same ages. Application of this method requires extensive compilation of historical aged retirement data and several related plant accounting data including additions

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LIFE ESTIMATION

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management's outlook for the future, and the typical range of lives used by other electric companies.

The selected amortization periods for certain other General Plant accounts are described in the section "Calculated Annual and Accrued Amortization."

Generally, the survivor curve estimates for the remainder of the accounts were based on judgments which considered the nature of the plant and equipment, a review of available historical retirement data and a general knowledge of the service lives for similar equipment in other electric companies.

For Account 362, Station Equipment, the historical data indicated service lives of 70 years or more for the overall experience band 1975-2018. More recent experience bands indicated service lives of 80 years or more. These results were well beyond what is typically experienced for this account and well beyond the expectations of the company's engineering management. This account includes equipment and devices typically found in a substation yard. Some of the assets in this account include power transformers, circuit breakers, relays, busbar and supporting structures, etc. Based on discussions with engineering conducted during our management meeting and field review, a range of service lives were determined for the major equipment types within this account as follows: 45 to 55 years for power transformers; 40 to 50 years for circuit breakers; 50 years for electromechanical relays, 25 years for solid state relays; 50 years or more for busbar, and supporting structures. The survivor curve estimate for Account 362, Station Equipment is the 53-R3 and is based primarily on informed judgment with consideration of all relevant factors.

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

Net Salvage Considerations

In each of this report related primarily to Pennsylvania rate regulation practice under which experienced cost of negative net salvage in primarily related to property actually retired after their originally expected service life for expected salvage were made to either the accrued depreciation or the calculated accrued depreciation for individual accounts The accounting provision for recovering negative net salvage in Pennsylvania typically is based on the amortization of experienced net salvage over a five year period However PECO had requested in their 1998 rate case Docket R-981990 to amortize experienced negative net salvage over the composite remaining life The Pennsylvania Public Utility Commission PUC granted PECO's request and the company has been utilizing this method since 1999

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property or an account the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures known as average service life and equal life group. In the average service life procedure the rate of annual depreciation is based on the average life or average remaining life of the group and this rate is applied to the surviving balance of the group. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recovered at the time of retirement, hereafter the cost of plant retired subject to average life is more than fully recovered. Over the entire life period the portion of cost not recovered prior to average life is balanced by the cost recovered subject to average life.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual amount over the total life is

$$\frac{\$1{,}000}{(4 + 6)} = \$100 \text{ per year.}$$

The accrued depreciation is

$$\$1{,}000\left(1 - \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

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Average Service Life Procedure

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$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

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ACCT	TITLE	AMORTIZATION PERIOD YEARS
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391	Office Furniture and Equipment	
391.1	Office Machines	10
391.2	Furniture and Fixtures	10
391.3	Computers	5
393	Stores Equipment	10
394	Tools Shop and Garage Equipment	
394.1	Construction Tools	10
394.2	Common Tools	10
394.3	Garage Equipment	20
397	Miscellaneous Equipment	10

For the purpose of calculating annual amortization and net salvage of December 31, 2018 the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage age to its amortization period. The annual amortization is determined by dividing the future amortization (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual accrual rates and amounts resulting from application of the depreciation rates and procedures are the principal results of this report. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect consideration of current historical evidence and expected future conditions. The annual depreciation accrual rates are applicable to the electric plant and reserve at January 1, 2019.

DESCRIPTION OF DETAILED TABULATIONS

Table 1 and 2 present summaries of the study applied to the original cost of electric plant and reserve at December 31, 2018. The remaining columns headed for each business division are presented on Pages VI-3 and VI-4 of this report.

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other electric utilities. The results of the statistical analysis of service life are presented in the section beginning on Page VII-1 within the supporting documents of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curve, followed by a tabular presentation of the original life table plotted on the chart. The survivor curve estimated for the depreciable group, is shown as a dark smooth curve on the chart. Each smooth

□r□or □r□e i□ de□oted b□ a □□□era□fo□o□ed b□ the □r□e t□□e de□g□atio□□ The □□□era□□□ed i□ the a□erage □ife deri□ed fro□ the e□tire □r□e fro□ 100 □er□e□t to □ero □er□e□t □r□i□g□ The tit□e□ of the □hart i□di□ate the gro□□□the □□□ bo□□□ed to □ot the □oi□t□ of the origi□a□ife tab□e□a□d the ex□erie□□e a□d □a□e□e□t ba□d□ of the □ife tab□e□ □hi□h □here □□otted□ The ex□erie□□e ba□d i□di□ate□the ra□ge of □ear□for □hi□h retire□e□t□ □ere □□ed to de□e□o□ the □t□b □r□i□or □r□e□ The □a□e□e□t□i□di□ate□for the re□ated ex□erie□□e ba□d□the ra□ge of □ear□ of i□□ta□□atio□□ □hi□h a□□ear i□ the ex□erie□□e□

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PECO ENERGY COMPANY
ELECTRIC PLANT

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2018

ACCOUNT		SURVIVOR CURVE	ORIGINAL COST AT 12/31/2018	BOOK RESERVE AT 12/31/2018	FUTURE ACCRUALS (NET PLANT)	COMPOSITE REMAINING LIFE	CALCULATED ANNUAL ACCRUAL AMOUNT	RATE (%) GROSS PLANT	RATE (%) NET PLANT
(1)		(2)	(3)	(4)	(5)=(3)-(4)	(6)	(7)	(8)=(7)/(3)	(9)=(7)/(5)
DEPRECIABLE PLANT									
DISTRIBUTION PLANT									
361	STRUCTURES AND IMPROVEMENTS	50 - R2.5	131,923,250	38,895,666	93,027,584	37.8	2,458,965	1.86	2.64
362	STATION EQUIPMENT	53 - R3	1,063,088,348	447,064,719	616,023,629	37.2	16,545,067	1.56	2.69
364	POLES, TOWERS AND FIXTURES	53 - R2	734,955,658	151,904,383	583,051,275	37.7	15,458,780	2.10	2.65
365	OVERHEAD CONDUCTORS AND DEVICES	52 - R2.5	1,266,604,582	271,957,577	994,647,005	37.6	26,486,255	2.09	2.66
366	UNDERGROUND CONDUIT	70 - R4	431,326,278	161,824,220	269,502,058	49.8	5,415,396	1.26	2.01
367	UNDERGROUND CONDUCTORS AND DEVICES	54 - S0.5	1,243,010,861	199,183,945	1,043,826,916	40.3	25,882,981	2.08	2.48
368	LINE TRANSFORMERS	47 - R1.5	602,928,338	188,592,017	414,336,321	33.2	12,484,325	2.07	3.01
369.1	SERVICES - AERIAL	53 - R4	153,909,691	53,375,212	100,534,479	36.3	2,770,502	1.80	2.76
369.2	SERVICES - UNDERGROUND	55 - R3	265,081,148	107,811,221	157,269,927	32.6	4,825,132	1.82	3.07
370.1	METER TRANSFORMERS	35 - R2	2,783,221	290,726	2,492,495	32.3	77,188	2.77	3.10
370.2	SMART METERS	15 - S2	305,275,591	96,785,355	208,490,236	10.4	20,012,793	6.56	9.60
371	INSTALLATIONS ON CUSTOMERS' PREMISES	36 - R4	1,030,123	952,878	77,245	16.4	4,716	0.46	6.11
373	STREET LIGHTING AND SIGNAL SYSTEMS	24 - L0	59,869,600	28,744,054	31,125,546	17.2	1,813,386	3.03	5.83
TOTAL DISTRIBUTION PLANT			**6,261,786,689**	**1,747,381,973**	**4,514,404,716**		**134,235,486**	**2.14**	**2.97**
GENERAL PLANT									
390	STRUCTURES AND IMPROVEMENTS	45 - S0	49,393,587	11,771,540	37,622,047	29.9	1,260,055	2.55	3.35
391.1	OFFICE FURNITURE AND EQUIPMENT - OFFICE MACHINES	10 - SQ	83,461	56,913	26,548	2.5	10,619	12.72	40.00
391.2	OFFICE FURNITURE AND EQUIPMENT - FURNITURE AND FIXTURES	15 - SQ	509,566	113,111	396,455	10.7	37,008	7.26	9.33
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	5 - SQ	22,992,598	7,539,039	15,453,559	3.7	4,204,772	18.29	27.21
391.4	OFFICE FURNITURE AND EQUIPMENT - SMART METER COMP. EQUIP.	5 - SQ	2,902,801	1,901,872	1,000,929	1.2	858,014	29.56	85.72
393	STORES EQUIPMENT	15 - SQ	46,470	6,982	39,488	9.2	4,297	9.25	10.88
394	TOOLS, SHOP AND GARAGE EQUIPMENT	15 - SQ	34,588,353	10,806,819	23,781,534	8.7	2,735,930	7.91	11.50
395.1	LABORATORY EQUIPMENT - TESTING	20 - SQ	311,026	214,531	96,495	6.8	14,228	4.57	14.74
395.2	LABORATORY EQUIPMENT - METERS	15 - SQ	101,381	75,266	26,115	3.5	7,461	7.36	28.57
397	COMMUNICATION EQUIPMENT	20 - L3	125,639,704	29,840,526	95,799,178	14.4	6,671,322	5.31	6.96
397.1	COMMUNICATION EQUIPMENT - SMART METERS	15 - S2	35,480,218	12,177,653	23,302,565	9.4	2,473,509	6.97	10.61
398	MISCELLANEOUS EQUIPMENT	15 - SQ	652,694	590,273	62,421	1.1	57,316	8.78	91.82
TOTAL GENERAL PLANT			**272,701,859**	**75,094,525**	**197,607,334**		**18,334,531**	**6.72**	**9.28**
TOTAL DEPRECIABLE PLANT			**6,534,488,548**	**1,822,476,498**	**4,712,012,050**		**152,570,017**		
NONDEPRECIABLE AND ACCOUNTS NOT STUDIED									
	TRANSMISSION PLANT (DEPRECIABLE)		1,548,649,512	507,904,458					
121	NON-UTILITY PROPERTY		11,837,171	1,800,839					
302	FRANCHISES AND CONSENTS		162,934	0					
303	MISCELLANEOUS INTANGIBLE PLANT*		162,783,557	110,985,499					
350	LAND AND LAND RIGHTS		62,970,795	0					
359.1	TRANSMISSION ARO COSTS		1,728	(405)					
360	LAND AND LAND RIGHTS		50,690,142	0					
370	METERS (AMR)		6,115	0					
371.1	INSTALLATIONS ON CUSTOMERS' PREMISES - DLC SWITCHES		12,742,260	6,157,542					
374	DISTRIBUTION ARO COSTS		2,021,740	2,186,839					
389	LAND AND LAND RIGHTS		1,063,459	0					
399.1	GENERAL ARO COSTS		1,656,099	347,666					
TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED			**1,854,585,512**	**629,382,438**					
TOTAL ELECTRIC PLANT			**8,389,074,060**	**2,451,858,936**					

* Miscellaneous Intangible Plant is individually depreciated over 5 years.

PECO ENERGY COMPANY
COMMON PLANT

TABLE 2. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO COMMON PLANT AT DECEMBER 31, 2018

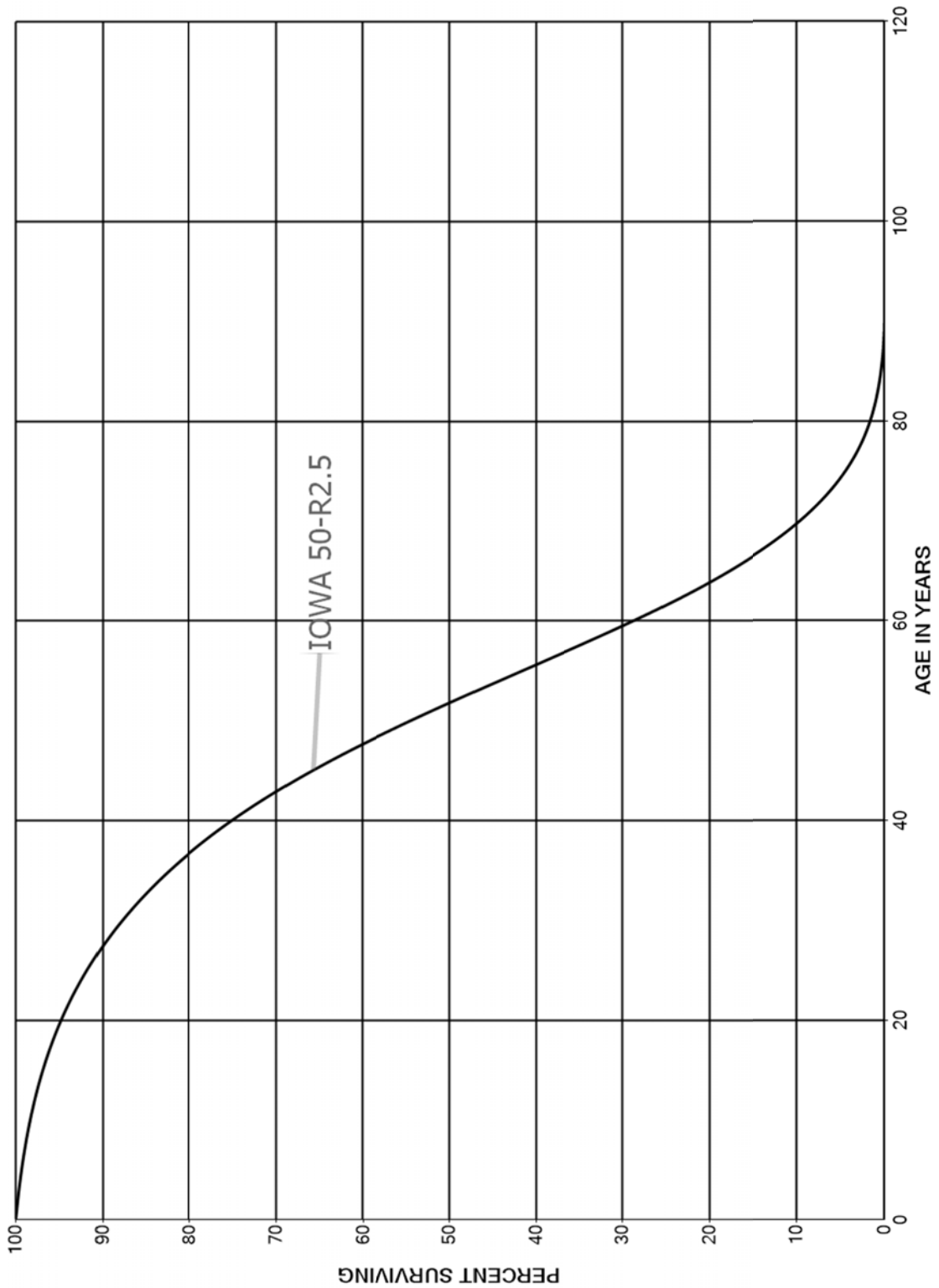
ACCOUNT		SURVIVOR CURVE	ORIGINAL COST AT 12/31/2018	BOOK RESERVE AT 12/31/2018	FUTURE ACCRUALS (NET PLANT)	COMPOSITE REMAINING LIFE	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%) GROSS PLANT	CALCULATED ANNUAL ACCRUAL RATE (%) NET PLANT
(1)		(2)	(3)	(4)	(5)=(3)-(4)	(6)	(7)	(8)=(7)/(3)	(9)=(7)/(5)
DEPRECIABLE PLANT									
GENERAL PLANT									
390	STRUCTURES AND IMPROVEMENTS	55 - R1	276,613,564	77,358,711	199,254,853	41.6	4,788,193	1.73	2.40
391.1	OFFICE FURNITURE AND EQUIPMENT - OFFICE MACHINES	10 - SQ	90,318	57,791	32,527	1.5	21,651	23.97	66.56
391.2	OFFICE FURNITURE AND EQUIPMENT - FURNITURE AND FIXTURES	15 - SQ	15,732,611	3,417,635	12,314,976	9.4	1,316,353	8.37	10.69
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	5 - SQ	31,957,627	14,117,570	17,840,057	2.8	6,385,877	19.98	35.80
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	6 - L3	93,640	92,857	783	4.5	173	0.18	22.09
392.2	TRANSPORTATION EQUIPMENT - LIGHT TRUCKS	12 - S4	33,344,723	16,446,700	16,898,023	8.4	2,003,546	6.01	11.86
392.3	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	14 - R4	79,052,417	35,954,218	43,098,199	8.7	4,976,258	6.29	11.55
392.4	TRANSPORTATION EQUIPMENT - TRACTORS	11 - L2	279,351	281,544	(2,193)	-	0	-	-
392.5	TRANSPORTATION EQUIPMENT - TRAILERS	14 - L1.5	4,929,447	2,426,502	2,502,945	10.7	233,008	4.73	9.31
392.6	TRANSPORTATION EQUIPMENT - OTHER VEHICLES	15 - L2	5,071,551	3,836,237	1,235,314	8.4	146,459	2.89	11.86
392.7	TRANSPORTATION EQUIPMENT - MEDIUM TRUCKS	8 - L4	8,909,932	827,531	8,082,401	7.3	1,110,706	12.47	13.74
393	STORES EQUIPMENT	15 - SQ	1,237,256	298,787	938,469	6.9	136,517	11.03	14.55
394.1	TOOLS, SHOP AND GARAGE EQUIPMENT - CONSTRUCTION TOOLS	15 - SQ	11,617	(31,889)	43,506	3.5	12,430	107.00	28.57
394.2	TOOLS, SHOP AND GARAGE EQUIPMENT - COMMON TOOLS	15 - SQ	1,031,452	54,001	977,451	13.7	71,451	6.93	7.31
394.3	TOOLS, SHOP AND GARAGE EQUIPMENT - GARAGE EQUIPMENT	20 - SQ	2,676,683	1,525,126	1,151,557	8.4	136,317	5.09	11.84
396	POWER OPERATED EQUIPMENT	12 - R1.5	185,066	181,409	3,657	2.2	1,701	0.92	46.51
397	COMMUNICATION EQUIPMENT	20 - L3	50,308,247	17,760,487	32,547,760	12.6	2,580,891	5.13	7.93
398	MISCELLANEOUS EQUIPMENT	15 - SQ	1,198,075	481,813	716,262	8.0	89,678	7.49	12.52
TOTAL GENERAL PLANT			**512,723,577**	**175,087,030**	**337,636,547**		**24,011,209**	**4.68**	**7.11**
TOTAL DEPRECIABLE PLANT			**512,723,577**	**175,087,030**	**337,636,547**		**24,011,209**		
NONDEPRECIABLE AND ACCOUNTS NOT STUDIED									
301	ORGANIZATION		677,136	0					
303	MISCELLANEOUS INTANGIBLE PLANT*		234,459,058	192,457,953					
389	LAND AND LAND RIGHTS		6,783,056	0					
399.1	GENERAL ARO COSTS		1,018,150	(355,373)					
TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED			**242,937,400**	**192,102,580**					
TOTAL COMMON PLANT			**755,660,977**	**367,189,610**					

* Miscellaneous Intangible Plant is individually depreciated over 5 years.

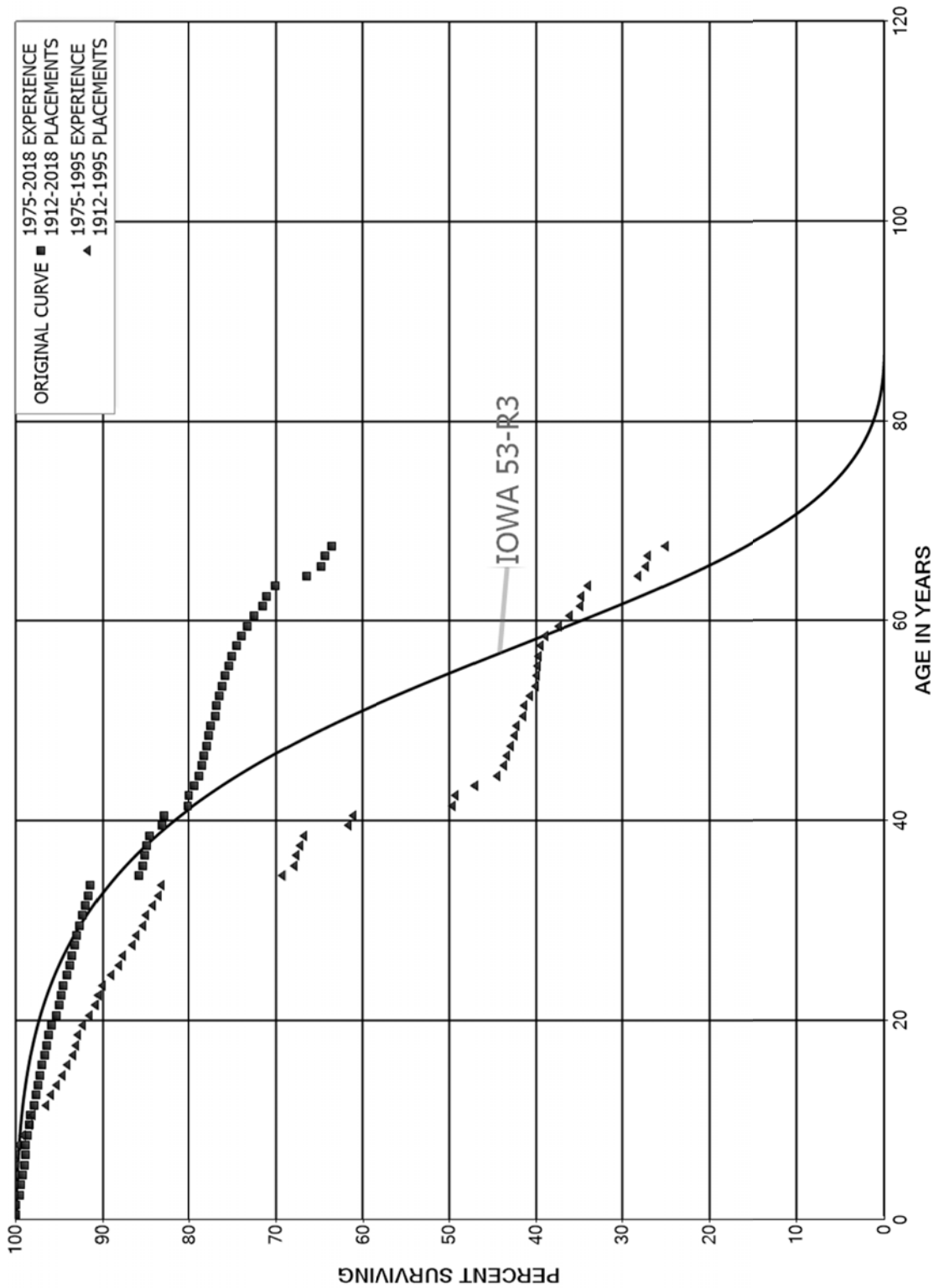
PART VII. SERVICE LIFE STATISTICS

ELECTRIC PLANT

PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 361 STRUCTURES AND IMPROVEMENTS
SMOOTH SURVIVOR CURVE



PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 362 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1912-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	895,283,645	29,931	0.0000	1.0000	100.00
0.5	874,578,043	807,225	0.0009	0.9991	100.00
1.5	832,224,239	3,123,428	0.0038	0.9962	99.90
2.5	801,799,909	764,129	0.0010	0.9990	99.53
3.5	778,953,866	2,142,803	0.0028	0.9972	99.43
4.5	765,413,049	1,612,043	0.0021	0.9979	99.16
5.5	767,492,326	587,432	0.0008	0.9992	98.95
6.5	768,022,953	689,420	0.0009	0.9991	98.88
7.5	725,898,751	1,235,451	0.0017	0.9983	98.79
8.5	701,299,891	1,434,655	0.0020	0.9980	98.62
9.5	675,270,633	872,892	0.0013	0.9987	98.42
10.5	639,749,067	2,804,405	0.0044	0.9956	98.29
11.5	610,961,277	1,737,686	0.0028	0.9972	97.86
12.5	581,744,070	1,147,806	0.0020	0.9980	97.58
13.5	577,092,992	1,344,464	0.0023	0.9977	97.39
14.5	565,836,163	1,263,389	0.0022	0.9978	97.16
15.5	553,133,683	1,617,867	0.0029	0.9971	96.95
16.5	550,932,642	1,405,177	0.0026	0.9974	96.66
17.5	519,407,326	1,528,162	0.0029	0.9971	96.41
18.5	514,437,605	1,299,644	0.0025	0.9975	96.13
19.5	504,487,425	3,092,209	0.0061	0.9939	95.89
20.5	471,604,003	1,472,358	0.0031	0.9969	95.30
21.5	467,620,504	1,305,003	0.0028	0.9972	95.00
22.5	450,221,081	1,239,777	0.0028	0.9972	94.74
23.5	436,520,785	1,919,715	0.0044	0.9956	94.48
24.5	429,866,158	1,486,348	0.0035	0.9965	94.06
25.5	417,451,635	807,951	0.0019	0.9981	93.74
26.5	384,944,946	1,755,139	0.0046	0.9954	93.55
27.5	363,576,874	756,124	0.0021	0.9979	93.13
28.5	325,182,998	1,031,482	0.0032	0.9968	92.93
29.5	295,601,427	1,028,702	0.0035	0.9965	92.64
30.5	271,742,019	989,079	0.0036	0.9964	92.32
31.5	255,793,470	1,106,445	0.0043	0.9957	91.98
32.5	254,019,690	523,843	0.0021	0.9979	91.58
33.5	247,349,227	14,934,524	0.0604	0.9396	91.39
34.5	224,837,801	1,396,568	0.0062	0.9938	85.88
35.5	219,497,211	557,610	0.0025	0.9975	85.34
36.5	217,503,970	601,155	0.0028	0.9972	85.13
37.5	212,415,319	611,740	0.0029	0.9971	84.89
38.5	209,411,211	3,723,144	0.0178	0.9822	84.65

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	202,012,979	571,447	0.0028	0.9972	83.14
40.5	200,157,042	6,500,351	0.0325	0.9675	82.91
41.5	190,987,533	448,311	0.0023	0.9977	80.21
42.5	191,872,992	1,454,722	0.0076	0.9924	80.03
43.5	182,782,621	1,358,863	0.0074	0.9926	79.42
44.5	166,820,159	634,716	0.0038	0.9962	78.83
45.5	159,758,892	418,739	0.0026	0.9974	78.53
46.5	144,407,817	578,300	0.0040	0.9960	78.32
47.5	128,478,391	519,723	0.0040	0.9960	78.01
48.5	116,735,143	328,243	0.0028	0.9972	77.69
49.5	101,938,362	708,099	0.0069	0.9931	77.48
50.5	96,026,739	162,693	0.0017	0.9983	76.94
51.5	89,992,835	364,325	0.0040	0.9960	76.81
52.5	85,939,965	360,672	0.0042	0.9958	76.50
53.5	82,180,957	411,449	0.0050	0.9950	76.17
54.5	77,671,585	447,849	0.0058	0.9942	75.79
55.5	72,040,036	260,305	0.0036	0.9964	75.36
56.5	68,496,610	559,793	0.0082	0.9918	75.08
57.5	62,526,261	472,673	0.0076	0.9924	74.47
58.5	56,709,046	488,653	0.0086	0.9914	73.91
59.5	51,314,296	561,915	0.0110	0.9890	73.27
60.5	45,089,180	622,261	0.0138	0.9862	72.47
61.5	40,333,701	229,613	0.0057	0.9943	71.47
62.5	34,853,025	493,231	0.0142	0.9858	71.06
63.5	31,492,606	1,601,735	0.0509	0.9491	70.06
64.5	26,068,081	658,762	0.0253	0.9747	66.49
65.5	21,593,049	127,386	0.0059	0.9941	64.81
66.5	20,218,329	250,129	0.0124	0.9876	64.43
67.5	18,173,400	117,578	0.0065	0.9935	63.63
68.5	16,327,057	264,626	0.0162	0.9838	63.22
69.5	14,553,913	221,354	0.0152	0.9848	62.20
70.5	13,667,543	80,059	0.0059	0.9941	61.25
71.5	9,532,731	37,449	0.0039	0.9961	60.89
72.5	9,326,071	25,895	0.0028	0.9972	60.65
73.5	8,421,301	53,390	0.0063	0.9937	60.48
74.5	8,018,039	6,459	0.0008	0.9992	60.10
75.5	7,769,754	10,376	0.0013	0.9987	60.05
76.5	6,609,373	37,087	0.0056	0.9944	59.97
77.5	6,417,754	5,441	0.0008	0.9992	59.64
78.5	6,332,251	150,559	0.0238	0.9762	59.58

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	6,117,786	33,704	0.0055	0.9945	58.17
80.5	6,049,025	76,057	0.0126	0.9874	57.85
81.5	5,951,621	89,423	0.0150	0.9850	57.12
82.5	5,861,432	108,978	0.0186	0.9814	56.26
83.5	5,752,454	17,557	0.0031	0.9969	55.22
84.5	5,734,882	376,921	0.0657	0.9343	55.05
85.5	5,351,539	5,685	0.0011	0.9989	51.43
86.5	3,624,528	14,025	0.0039	0.9961	51.37
87.5	3,392,531	72,485	0.0214	0.9786	51.18
88.5	3,100,231	11,424	0.0037	0.9963	50.08
89.5	2,049,199	124,266	0.0606	0.9394	49.90
90.5	1,869,372	13,747	0.0074	0.9926	46.87
91.5	1,824,102	11,518	0.0063	0.9937	46.53
92.5	1,740,960	12,886	0.0074	0.9926	46.23
93.5	1,473,693	274	0.0002	0.9998	45.89
94.5	787,379	2,291	0.0029	0.9971	45.88
95.5	88,041	5,298	0.0602	0.9398	45.75
96.5	78,751	92	0.0012	0.9988	43.00
97.5	76,392	749	0.0098	0.9902	42.95
98.5	22,316	37	0.0017	0.9983	42.53
99.5	21,867	3	0.0001	0.9999	42.46
100.5	21,864	162	0.0074	0.9926	42.45
101.5	19,748	24	0.0012	0.9988	42.14
102.5					42.09

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1912-1995 EXPERIENCE BAND 1975-1995

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	277,640,124		0.0000	1.0000	100.00
0.5	278,932,497	84,948	0.0003	0.9997	100.00
1.5	280,541,278	57,795	0.0002	0.9998	99.97
2.5	270,115,781	92,854	0.0003	0.9997	99.95
3.5	254,221,628	77,280	0.0003	0.9997	99.91
4.5	243,303,255	149,747	0.0006	0.9994	99.88
5.5	221,866,727	83,392	0.0004	0.9996	99.82
6.5	200,643,697	309,360	0.0015	0.9985	99.79
7.5	181,324,760	1,027,371	0.0057	0.9943	99.63
8.5	170,149,829	1,273,330	0.0075	0.9925	99.07
9.5	164,510,302	569,131	0.0035	0.9965	98.33
10.5	162,501,583	2,691,546	0.0166	0.9834	97.99
11.5	158,146,298	890,882	0.0056	0.9944	96.36
12.5	157,913,532	1,010,870	0.0064	0.9936	95.82
13.5	162,041,288	1,153,787	0.0071	0.9929	95.21
14.5	162,916,818	977,600	0.0060	0.9940	94.53
15.5	164,649,163	1,151,270	0.0070	0.9930	93.96
16.5	166,285,503	622,308	0.0037	0.9963	93.30
17.5	169,426,196	395,756	0.0023	0.9977	92.95
18.5	173,354,054	1,061,265	0.0061	0.9939	92.74
19.5	176,385,381	1,439,529	0.0082	0.9918	92.17
20.5	170,899,076	1,192,777	0.0070	0.9930	91.42
21.5	159,017,250	754,631	0.0047	0.9953	90.78
22.5	152,318,574	616,007	0.0040	0.9960	90.35
23.5	137,827,455	1,663,357	0.0121	0.9879	89.98
24.5	121,972,597	1,104,238	0.0091	0.9909	88.90
25.5	126,448,751	653,737	0.0052	0.9948	88.09
26.5	112,045,216	1,465,747	0.0131	0.9869	87.64
27.5	107,319,208	547,358	0.0051	0.9949	86.49
28.5	99,984,447	855,393	0.0086	0.9914	86.05
29.5	95,925,748	375,602	0.0039	0.9961	85.31
30.5	95,621,322	846,648	0.0089	0.9911	84.98
31.5	90,574,298	733,469	0.0081	0.9919	84.23
32.5	91,556,898	398,828	0.0044	0.9956	83.55
33.5	87,821,867	14,775,943	0.1682	0.8318	83.18
34.5	67,311,717	1,313,314	0.0195	0.9805	69.19
35.5	60,526,173	218,061	0.0036	0.9964	67.84
36.5	56,414,385	375,639	0.0067	0.9933	67.59
37.5	50,211,929	336,316	0.0067	0.9933	67.14
38.5	45,667,115	3,441,734	0.0754	0.9246	66.69

PECO ENERGY COMPANY
ELECTRIC PLANT

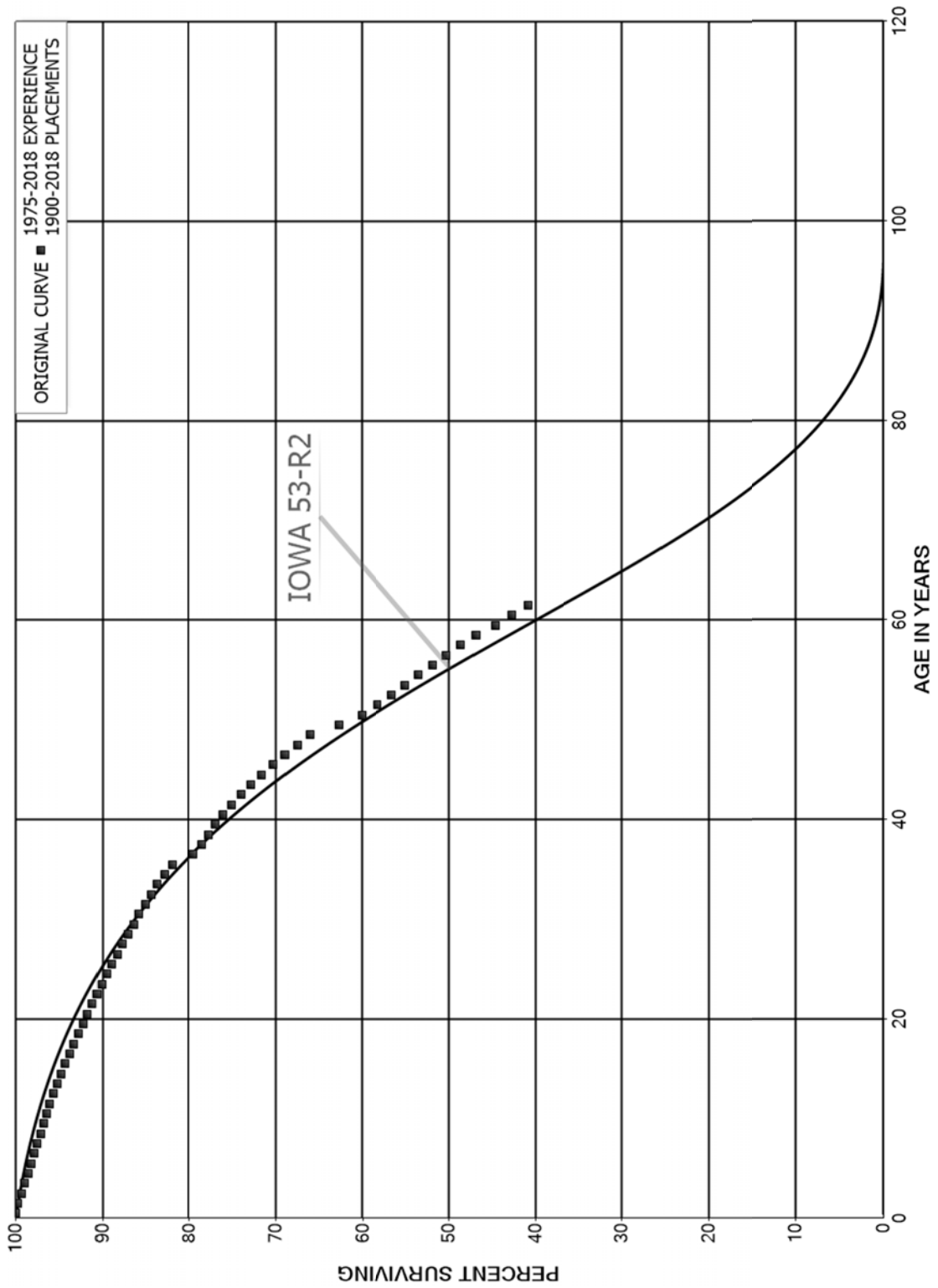
ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-1995 EXPERIENCE BAND 1975-1995

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	36,807,512	345,830	0.0094	0.9906	61.67
40.5	32,948,948	6,255,467	0.1899	0.8101	61.09
41.5	22,845,178	164,450	0.0072	0.9928	49.49
42.5	20,182,939	910,630	0.0451	0.9549	49.13
43.5	19,557,753	1,053,023	0.0538	0.9462	46.92
44.5	17,133,429	291,679	0.0170	0.9830	44.39
45.5	16,221,495	112,595	0.0069	0.9931	43.63
46.5	14,743,301	165,527	0.0112	0.9888	43.33
47.5	14,041,569	132,047	0.0094	0.9906	42.84
48.5	10,367,392	53,150	0.0051	0.9949	42.44
49.5	10,884,683	211,050	0.0194	0.9806	42.22
50.5	10,746,498	23,553	0.0022	0.9978	41.41
51.5	11,384,592	185,612	0.0163	0.9837	41.31
52.5	10,945,715	175,008	0.0160	0.9840	40.64
53.5	9,407,540	32,190	0.0034	0.9966	39.99
54.5	9,236,741	27,199	0.0029	0.9971	39.85
55.5	9,569,618	23,940	0.0025	0.9975	39.74
56.5	9,438,559	51,552	0.0055	0.9945	39.64
57.5	9,320,777	150,669	0.0162	0.9838	39.42
58.5	9,124,986	342,998	0.0376	0.9624	38.78
59.5	8,781,322	331,022	0.0377	0.9623	37.33
60.5	8,450,300	270,466	0.0320	0.9680	35.92
61.5	8,193,050	42,541	0.0052	0.9948	34.77
62.5	8,051,547	165,324	0.0205	0.9795	34.59
63.5	6,102,394	1,045,180	0.1713	0.8287	33.88
64.5	4,663,267	149,009	0.0320	0.9680	28.08
65.5	4,103,354	38,964	0.0095	0.9905	27.18
66.5	3,001,726	216,325	0.0721	0.9279	26.92
67.5	2,337,157	24,926	0.0107	0.9893	24.98
68.5	2,268,053	72,108	0.0318	0.9682	24.71
69.5	1,915,645		0.0000	1.0000	23.93
70.5	1,619,702	3,578	0.0022	0.9978	23.93
71.5	894,840	9,880	0.0110	0.9890	23.88
72.5	104,497		0.0000	1.0000	23.61
73.5	93,719		0.0000	1.0000	23.61
74.5	88,313		0.0000	1.0000	23.61
75.5	24,885		0.0000	1.0000	23.61
76.5	24,176		0.0000	1.0000	23.61
77.5	24,176		0.0000	1.0000	23.61
78.5	22,213		0.0000	1.0000	23.61
79.5					23.61

PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 364 POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 364 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	727,946,827	583,345	0.0008	0.9992	100.00
0.5	686,597,114	1,556,474	0.0023	0.9977	99.92
1.5	658,490,280	2,972,434	0.0045	0.9955	99.69
2.5	633,507,735	2,064,664	0.0033	0.9967	99.24
3.5	607,257,110	2,413,620	0.0040	0.9960	98.92
4.5	583,785,276	1,945,062	0.0033	0.9967	98.53
5.5	566,799,102	2,147,881	0.0038	0.9962	98.20
6.5	545,394,578	2,092,378	0.0038	0.9962	97.83
7.5	518,886,152	1,931,814	0.0037	0.9963	97.45
8.5	495,725,881	1,654,270	0.0033	0.9967	97.09
9.5	446,685,550	1,564,057	0.0035	0.9965	96.76
10.5	431,927,297	1,787,817	0.0041	0.9959	96.43
11.5	431,490,329	1,798,811	0.0042	0.9958	96.03
12.5	426,649,284	2,014,782	0.0047	0.9953	95.63
13.5	411,594,205	1,990,362	0.0048	0.9952	95.17
14.5	402,498,043	1,883,396	0.0047	0.9953	94.71
15.5	374,698,839	1,957,775	0.0052	0.9948	94.27
16.5	347,846,235	1,903,331	0.0055	0.9945	93.78
17.5	309,859,104	1,773,897	0.0057	0.9943	93.27
18.5	302,416,433	1,673,602	0.0055	0.9945	92.73
19.5	281,897,749	1,607,586	0.0057	0.9943	92.22
20.5	265,983,244	1,530,970	0.0058	0.9942	91.69
21.5	252,745,649	1,498,165	0.0059	0.9941	91.16
22.5	234,930,474	1,431,503	0.0061	0.9939	90.62
23.5	224,599,197	1,434,196	0.0064	0.9936	90.07
24.5	214,548,483	1,404,167	0.0065	0.9935	89.50
25.5	200,612,105	1,387,890	0.0069	0.9931	88.91
26.5	187,485,434	1,284,342	0.0069	0.9931	88.30
27.5	177,600,362	1,235,497	0.0070	0.9930	87.69
28.5	165,368,691	1,209,094	0.0073	0.9927	87.08
29.5	151,555,455	1,130,751	0.0075	0.9925	86.44
30.5	140,406,676	1,166,841	0.0083	0.9917	85.80
31.5	127,861,008	1,044,179	0.0082	0.9918	85.09
32.5	117,891,783	997,836	0.0085	0.9915	84.39
33.5	109,337,895	1,040,148	0.0095	0.9905	83.68
34.5	102,178,655	1,082,763	0.0106	0.9894	82.88
35.5	96,725,094	2,979,198	0.0308	0.9692	82.00
36.5	89,520,151	1,076,468	0.0120	0.9880	79.48
37.5	84,732,080	839,274	0.0099	0.9901	78.52
38.5	80,707,541	881,243	0.0109	0.9891	77.74

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 364 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	76,842,476	841,984	0.0110	0.9890	76.89
40.5	72,764,471	957,386	0.0132	0.9868	76.05
41.5	68,752,157	956,959	0.0139	0.9861	75.05
42.5	65,296,565	1,052,689	0.0161	0.9839	74.01
43.5	61,708,821	1,025,247	0.0166	0.9834	72.81
44.5	56,910,457	1,046,723	0.0184	0.9816	71.60
45.5	52,923,003	1,039,806	0.0196	0.9804	70.29
46.5	49,192,706	1,000,477	0.0203	0.9797	68.91
47.5	45,501,212	957,750	0.0210	0.9790	67.50
48.5	40,620,619	2,058,235	0.0507	0.9493	66.08
49.5	34,657,750	1,457,945	0.0421	0.9579	62.74
50.5	31,006,413	954,415	0.0308	0.9692	60.10
51.5	28,830,368	790,850	0.0274	0.9726	58.25
52.5	26,659,111	737,712	0.0277	0.9723	56.65
53.5	25,978,915	756,254	0.0291	0.9709	55.08
54.5	23,195,316	727,807	0.0314	0.9686	53.48
55.5	20,482,549	620,216	0.0303	0.9697	51.80
56.5	17,853,112	559,921	0.0314	0.9686	50.23
57.5	15,003,017	544,871	0.0363	0.9637	48.66
58.5	12,535,508	604,851	0.0483	0.9517	46.89
59.5	10,383,957	437,858	0.0422	0.9578	44.63
60.5	8,202,616	369,358	0.0450	0.9550	42.74
61.5	6,728,578	350,950	0.0522	0.9478	40.82
62.5	5,265,648	288,087	0.0547	0.9453	38.69
63.5	4,169,935	185,660	0.0445	0.9555	36.57
64.5	3,327,656	161,749	0.0486	0.9514	34.95
65.5	2,876,684	193,551	0.0673	0.9327	33.25
66.5	2,683,133	203,916	0.0760	0.9240	31.01
67.5	2,147,189	133,274	0.0621	0.9379	28.65
68.5	1,799,132	97,830	0.0544	0.9456	26.87
69.5	1,465,944	77,128	0.0526	0.9474	25.41
70.5	1,195,535	55,203	0.0462	0.9538	24.08
71.5	1,040,185	43,584	0.0419	0.9581	22.96
72.5	900,902	46,827	0.0520	0.9480	22.00
73.5	773,103	48,822	0.0632	0.9368	20.86
74.5	819,583	41,263	0.0503	0.9497	19.54
75.5	723,217	120,276	0.1663	0.8337	18.56
76.5	485,771	56,702	0.1167	0.8833	15.47
77.5	429,069	22,745	0.0530	0.9470	13.67
78.5	406,324	16,416	0.0404	0.9596	12.94

PECO ENERGY COMPANY
ELECTRIC PLANT

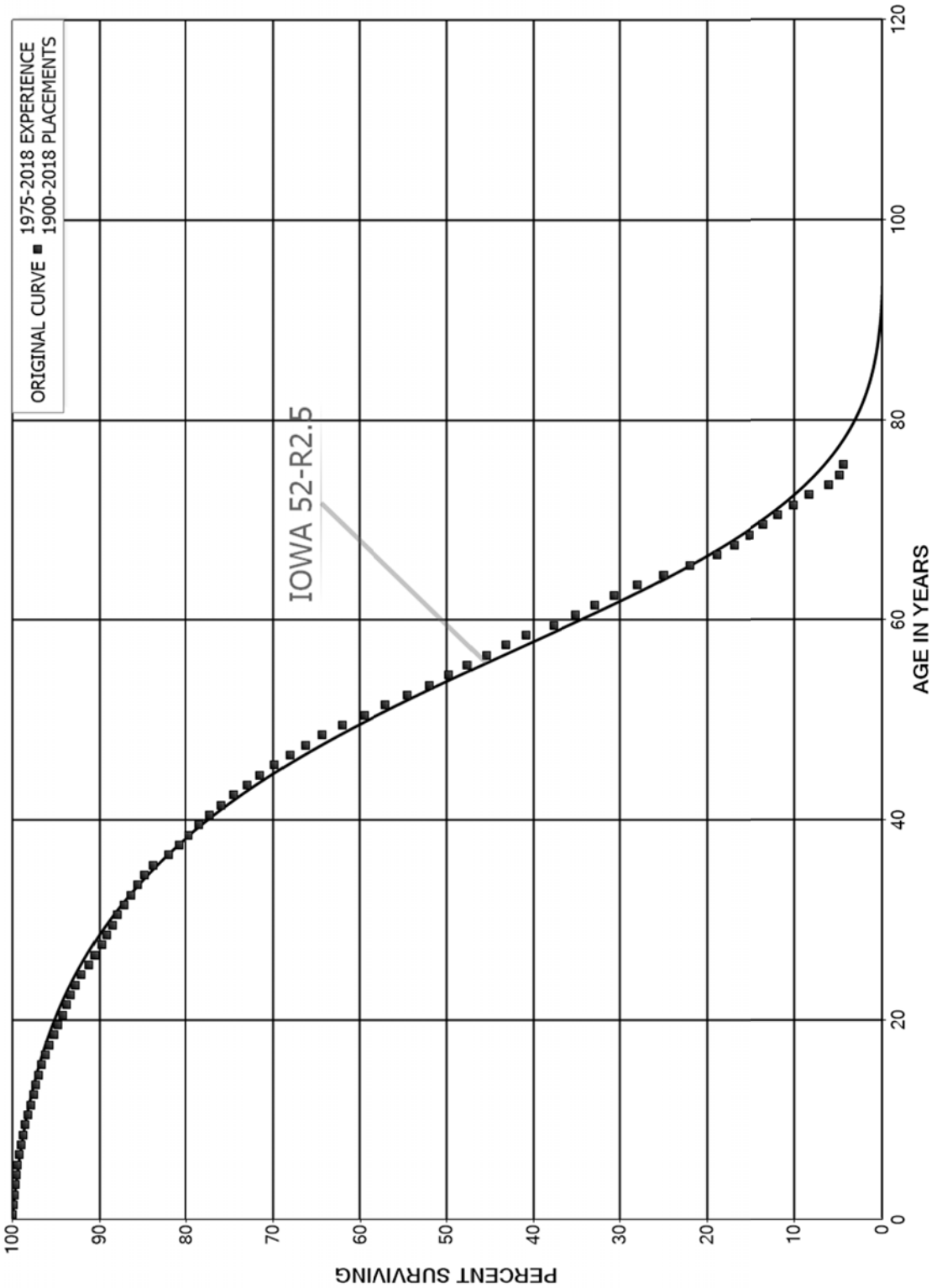
ACCOUNT 364 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	386,870	14,717	0.0380	0.9620	12.42
80.5	353,995	15,106	0.0427	0.9573	11.95
81.5	330,731	14,166	0.0428	0.9572	11.44
82.5	295,932	14,677	0.0496	0.9504	10.95
83.5	263,973	11,732	0.0444	0.9556	10.40
84.5	243,802	10,536	0.0432	0.9568	9.94
85.5	226,431	7,828	0.0346	0.9654	9.51
86.5	213,797	8,267	0.0387	0.9613	9.18
87.5	198,452	5,115	0.0258	0.9742	8.83
88.5	186,315	3,443	0.0185	0.9815	8.60
89.5	175,489	655	0.0037	0.9963	8.44
90.5	168,706	8,301	0.0492	0.9508	8.41
91.5	160,405	8,306	0.0518	0.9482	8.00
92.5	152,099	22,608	0.1486	0.8514	7.58
93.5	129,491	41,534	0.3207	0.6793	6.45
94.5	87,957	74,127	0.8428	0.1572	4.38
95.5	13,830	13,830	1.0000		0.69
96.5					

PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,244,701,614	485,337	0.0004	0.9996	100.00
0.5	1,162,409,840	1,054,583	0.0009	0.9991	99.96
1.5	1,095,638,098	1,566,043	0.0014	0.9986	99.87
2.5	1,043,945,744	1,221,673	0.0012	0.9988	99.73
3.5	993,731,623	1,158,436	0.0012	0.9988	99.61
4.5	933,406,644	1,290,249	0.0014	0.9986	99.49
5.5	909,028,724	1,799,704	0.0020	0.9980	99.36
6.5	868,134,164	2,105,262	0.0024	0.9976	99.16
7.5	821,196,941	2,071,324	0.0025	0.9975	98.92
8.5	777,292,834	1,691,989	0.0022	0.9978	98.67
9.5	655,710,263	1,991,804	0.0030	0.9970	98.46
10.5	635,268,848	1,928,957	0.0030	0.9970	98.16
11.5	617,643,265	1,918,492	0.0031	0.9969	97.86
12.5	614,509,635	1,892,390	0.0031	0.9969	97.55
13.5	572,077,551	1,790,082	0.0031	0.9969	97.25
14.5	564,779,348	1,990,672	0.0035	0.9965	96.95
15.5	547,135,317	2,385,000	0.0044	0.9956	96.61
16.5	523,349,464	2,727,253	0.0052	0.9948	96.19
17.5	501,206,015	2,553,981	0.0051	0.9949	95.69
18.5	498,167,600	2,503,891	0.0050	0.9950	95.20
19.5	479,639,665	2,562,117	0.0053	0.9947	94.72
20.5	444,354,921	2,267,261	0.0051	0.9949	94.21
21.5	421,230,162	2,222,247	0.0053	0.9947	93.73
22.5	383,802,632	2,025,672	0.0053	0.9947	93.24
23.5	356,463,443	2,432,953	0.0068	0.9932	92.75
24.5	334,270,250	3,211,912	0.0096	0.9904	92.11
25.5	310,584,959	2,601,135	0.0084	0.9916	91.23
26.5	289,058,634	2,266,922	0.0078	0.9922	90.46
27.5	273,124,405	1,910,551	0.0070	0.9930	89.75
28.5	251,802,712	1,756,149	0.0070	0.9930	89.13
29.5	226,819,068	1,513,162	0.0067	0.9933	88.51
30.5	210,990,733	1,809,077	0.0086	0.9914	87.91
31.5	194,081,218	1,630,795	0.0084	0.9916	87.16
32.5	182,191,229	1,637,772	0.0090	0.9910	86.43
33.5	172,290,557	1,735,733	0.0101	0.9899	85.65
34.5	162,897,553	1,890,176	0.0116	0.9884	84.79
35.5	155,598,359	3,328,934	0.0214	0.9786	83.81
36.5	146,786,730	2,172,869	0.0148	0.9852	82.01
37.5	138,842,498	1,831,216	0.0132	0.9868	80.80
38.5	130,847,030	1,999,032	0.0153	0.9847	79.73

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	123,589,134	1,893,184	0.0153	0.9847	78.51
40.5	117,256,547	2,113,796	0.0180	0.9820	77.31
41.5	111,314,822	2,025,164	0.0182	0.9818	75.92
42.5	105,010,230	2,167,752	0.0206	0.9794	74.54
43.5	99,010,850	2,032,254	0.0205	0.9795	73.00
44.5	90,786,864	2,102,340	0.0232	0.9768	71.50
45.5	82,696,852	2,081,537	0.0252	0.9748	69.84
46.5	76,147,542	2,013,660	0.0264	0.9736	68.09
47.5	69,073,360	1,985,855	0.0287	0.9713	66.29
48.5	60,140,033	2,113,025	0.0351	0.9649	64.38
49.5	50,554,950	2,097,501	0.0415	0.9585	62.12
50.5	44,969,204	1,847,303	0.0411	0.9589	59.54
51.5	40,061,712	1,802,174	0.0450	0.9550	57.09
52.5	35,411,513	1,639,116	0.0463	0.9537	54.53
53.5	31,444,666	1,357,802	0.0432	0.9568	52.00
54.5	24,988,432	1,096,040	0.0439	0.9561	49.76
55.5	19,876,786	930,804	0.0468	0.9532	47.57
56.5	15,981,380	765,263	0.0479	0.9521	45.35
57.5	11,776,637	628,064	0.0533	0.9467	43.18
58.5	8,926,410	702,829	0.0787	0.9213	40.87
59.5	6,603,349	447,590	0.0678	0.9322	37.65
60.5	5,186,890	335,584	0.0647	0.9353	35.10
61.5	4,065,668	272,882	0.0671	0.9329	32.83
62.5	3,198,986	281,104	0.0879	0.9121	30.63
63.5	2,723,560	292,075	0.1072	0.8928	27.94
64.5	2,371,767	286,020	0.1206	0.8794	24.94
65.5	1,954,601	274,602	0.1405	0.8595	21.93
66.5	1,616,284	171,251	0.1060	0.8940	18.85
67.5	1,134,062	116,911	0.1031	0.8969	16.85
68.5	813,447	89,182	0.1096	0.8904	15.12
69.5	582,254	69,645	0.1196	0.8804	13.46
70.5	466,199	69,536	0.1492	0.8508	11.85
71.5	372,781	65,530	0.1758	0.8242	10.08
72.5	279,697	77,096	0.2756	0.7244	8.31
73.5	187,616	36,020	0.1920	0.8080	6.02
74.5	353,976	37,629	0.1063	0.8937	4.86
75.5	308,178	26,812	0.0870	0.9130	4.35
76.5	266,702	18,172	0.0681	0.9319	3.97
77.5	248,531	12,632	0.0508	0.9492	3.70
78.5	232,744	3,291	0.0141	0.9859	3.51

PECO ENERGY COMPANY
ELECTRIC PLANT

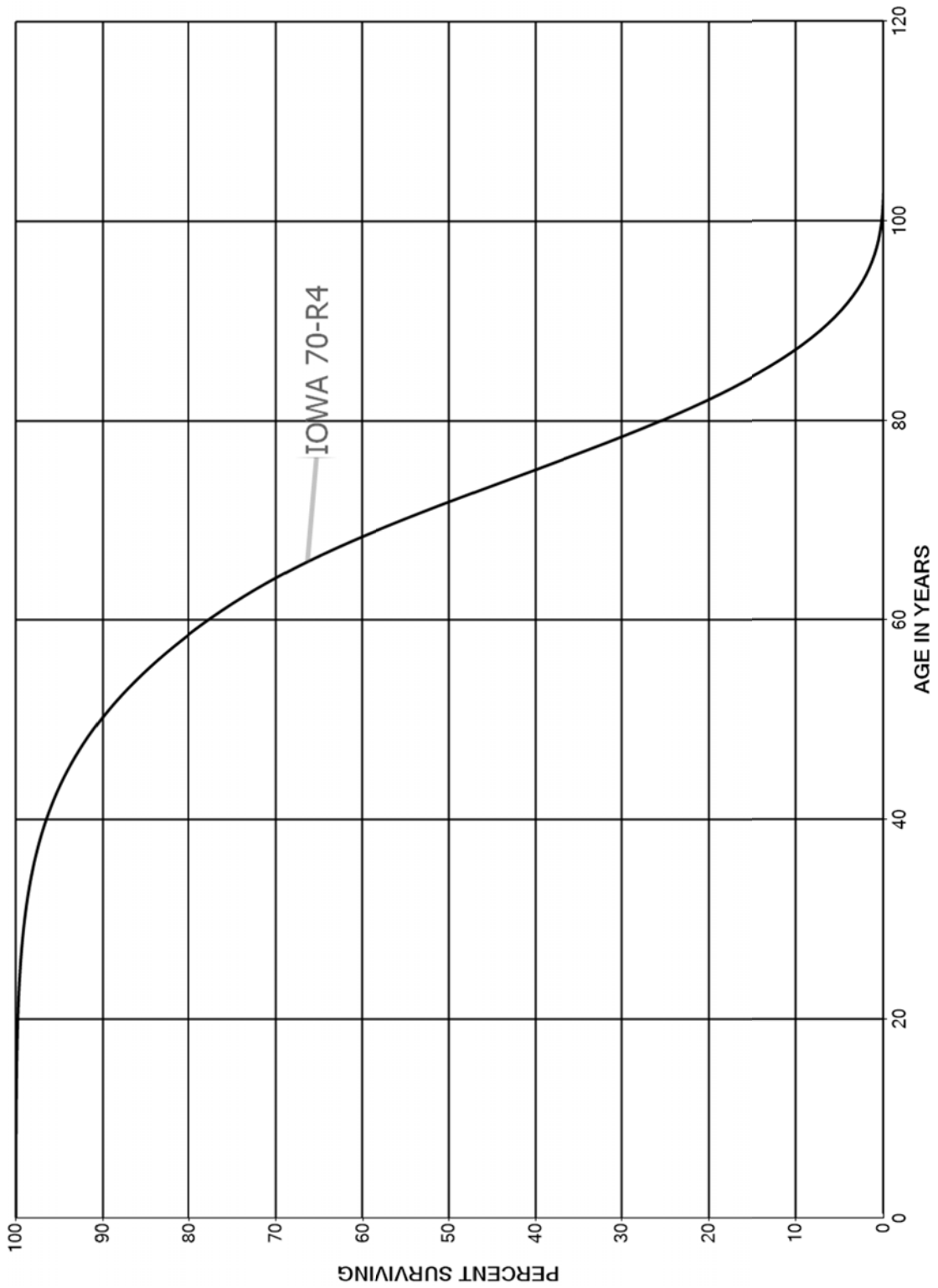
ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

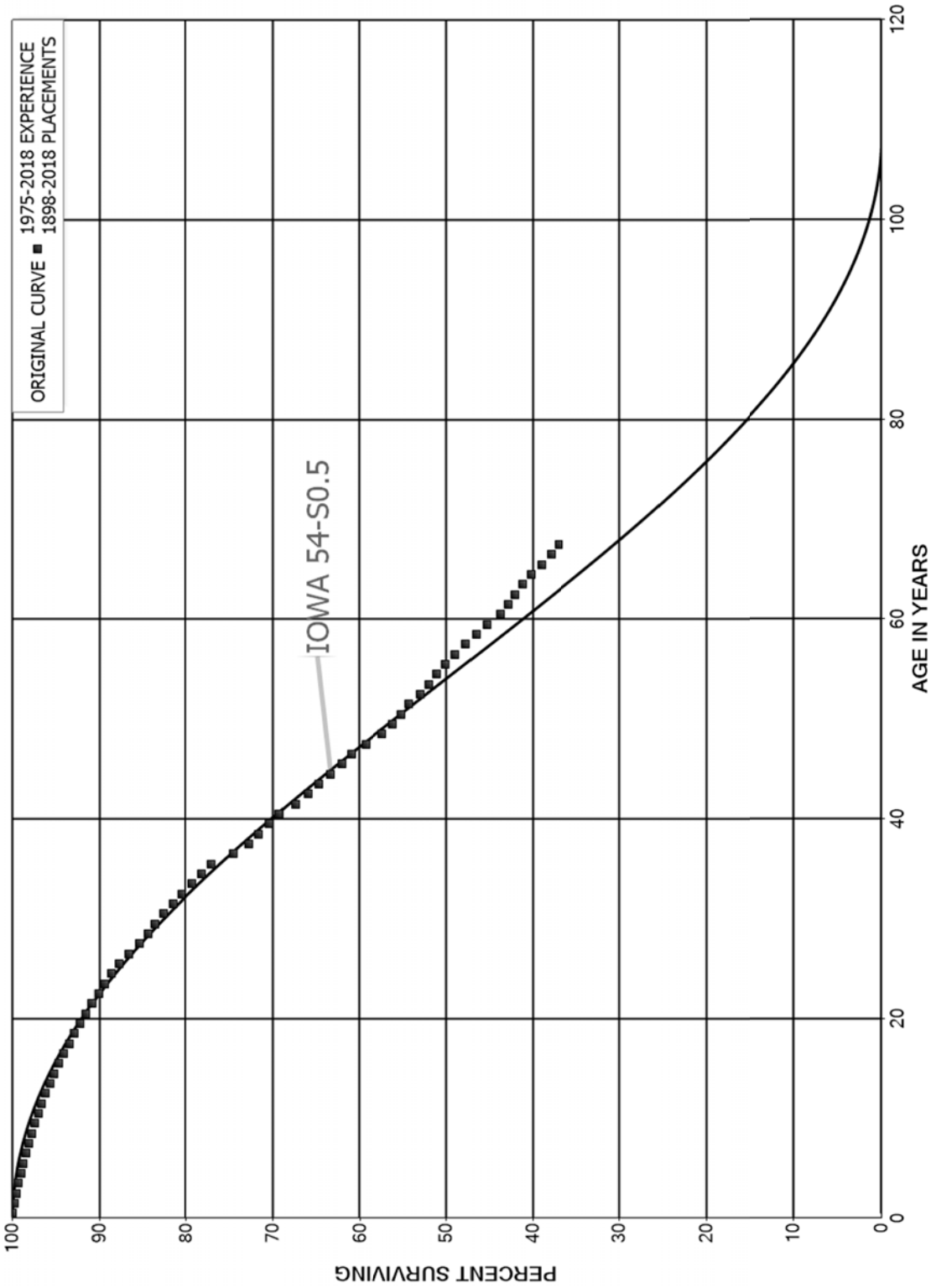
PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	222,488	2,085	0.0094	0.9906	3.46
80.5	220,045	585	0.0027	0.9973	3.43
81.5	219,284	400	0.0018	0.9982	3.42
82.5	218,792	298	0.0014	0.9986	3.41
83.5	218,426	202	0.0009	0.9991	3.41
84.5	218,041	109	0.0005	0.9995	3.40
85.5	217,825	42	0.0002	0.9998	3.40
86.5	217,756	26	0.0001	0.9999	3.40
87.5	217,678		0.0000	1.0000	3.40
88.5	217,678		0.0000	1.0000	3.40
89.5	217,678		0.0000	1.0000	3.40
90.5	217,678	48,863	0.2245	0.7755	3.40
91.5	168,814	68,569	0.4062	0.5938	2.64
92.5	100,245	11,697	0.1167	0.8833	1.57
93.5	88,548	63,964	0.7224	0.2776	1.38
94.5	24,584	24,236	0.9859	0.0141	0.38
95.5	348		0.0000	1.0000	0.01
96.5	348	348	1.0000		0.01
97.5					

PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 366 UNDERGROUND CONDUIT
SMOOTH SURVIVOR CURVE



PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1898-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,254,910,066	776,321	0.0006	0.9994	100.00
0.5	1,188,673,076	2,092,489	0.0018	0.9982	99.94
1.5	1,130,705,767	2,987,377	0.0026	0.9974	99.76
2.5	1,063,121,431	2,534,342	0.0024	0.9976	99.50
3.5	1,014,236,422	3,036,813	0.0030	0.9970	99.26
4.5	975,688,906	2,875,093	0.0029	0.9971	98.96
5.5	937,034,714	3,093,886	0.0033	0.9967	98.67
6.5	904,470,599	2,952,157	0.0033	0.9967	98.35
7.5	854,307,089	2,959,780	0.0035	0.9965	98.03
8.5	820,857,014	2,772,007	0.0034	0.9966	97.69
9.5	737,635,061	2,758,878	0.0037	0.9963	97.36
10.5	698,195,754	2,793,291	0.0040	0.9960	96.99
11.5	655,903,532	2,776,866	0.0042	0.9958	96.60
12.5	619,932,982	3,492,925	0.0056	0.9944	96.20
13.5	569,857,471	2,901,459	0.0051	0.9949	95.65
14.5	562,593,414	3,048,677	0.0054	0.9946	95.17
15.5	537,080,669	3,275,128	0.0061	0.9939	94.65
16.5	510,127,809	3,392,170	0.0066	0.9934	94.07
17.5	470,820,753	3,249,412	0.0069	0.9931	93.45
18.5	461,794,545	3,268,879	0.0071	0.9929	92.80
19.5	449,786,410	3,275,164	0.0073	0.9927	92.15
20.5	436,602,451	3,203,631	0.0073	0.9927	91.47
21.5	418,966,084	3,275,295	0.0078	0.9922	90.80
22.5	400,250,831	3,298,968	0.0082	0.9918	90.09
23.5	389,928,132	3,174,567	0.0081	0.9919	89.35
24.5	378,035,610	3,792,738	0.0100	0.9900	88.62
25.5	357,307,381	4,650,671	0.0130	0.9870	87.73
26.5	341,483,895	4,639,741	0.0136	0.9864	86.59
27.5	321,265,213	3,635,666	0.0113	0.9887	85.42
28.5	290,683,124	3,055,418	0.0105	0.9895	84.45
29.5	264,393,995	2,870,986	0.0109	0.9891	83.56
30.5	240,208,451	3,247,095	0.0135	0.9865	82.65
31.5	220,117,232	2,773,933	0.0126	0.9874	81.54
32.5	203,862,435	3,127,657	0.0153	0.9847	80.51
33.5	188,148,495	2,659,565	0.0141	0.9859	79.27
34.5	174,068,877	2,342,781	0.0135	0.9865	78.15
35.5	160,619,438	5,448,135	0.0339	0.9661	77.10
36.5	148,029,977	3,430,450	0.0232	0.9768	74.49
37.5	136,536,184	2,172,643	0.0159	0.9841	72.76
38.5	127,112,468	2,083,919	0.0164	0.9836	71.60

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1898-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	116,647,458	1,836,623	0.0157	0.9843	70.43
40.5	107,902,468	3,028,308	0.0281	0.9719	69.32
41.5	98,466,231	2,102,030	0.0213	0.9787	67.37
42.5	90,556,383	1,699,593	0.0188	0.9812	65.94
43.5	84,703,547	1,763,199	0.0208	0.9792	64.70
44.5	76,609,139	1,551,877	0.0203	0.9797	63.35
45.5	72,593,772	1,256,703	0.0173	0.9827	62.07
46.5	66,214,805	1,894,387	0.0286	0.9714	60.99
47.5	59,447,116	1,853,979	0.0312	0.9688	59.25
48.5	53,478,275	1,162,952	0.0217	0.9783	57.40
49.5	48,719,294	839,919	0.0172	0.9828	56.15
50.5	45,279,317	748,383	0.0165	0.9835	55.18
51.5	41,638,055	1,047,467	0.0252	0.9748	54.27
52.5	37,836,358	644,548	0.0170	0.9830	52.91
53.5	36,183,857	642,624	0.0178	0.9822	52.01
54.5	30,465,387	638,270	0.0210	0.9790	51.08
55.5	28,583,414	623,140	0.0218	0.9782	50.01
56.5	26,705,631	641,294	0.0240	0.9760	48.92
57.5	24,802,321	618,932	0.0250	0.9750	47.75
58.5	23,394,669	636,708	0.0272	0.9728	46.56
59.5	21,715,720	767,416	0.0353	0.9647	45.29
60.5	20,540,593	405,056	0.0197	0.9803	43.69
61.5	18,700,936	352,115	0.0188	0.9812	42.83
62.5	16,617,937	345,141	0.0208	0.9792	42.02
63.5	15,524,536	366,008	0.0236	0.9764	41.15
64.5	15,108,198	482,102	0.0319	0.9681	40.18
65.5	14,028,258	373,943	0.0267	0.9733	38.90
66.5	13,262,287	320,245	0.0241	0.9759	37.86
67.5	11,714,793	300,172	0.0256	0.9744	36.94
68.5	10,389,888	207,382	0.0200	0.9800	36.00
69.5	8,790,686	210,013	0.0239	0.9761	35.28
70.5	8,076,401	181,912	0.0225	0.9775	34.44
71.5	7,848,294	242,028	0.0308	0.9692	33.66
72.5	7,561,606	350,208	0.0463	0.9537	32.62
73.5	7,154,742	444,738	0.0622	0.9378	31.11
74.5	6,714,921	593,686	0.0884	0.9116	29.18
75.5	6,125,801	514,449	0.0840	0.9160	26.60
76.5	5,613,451	979,501	0.1745	0.8255	24.36
77.5	4,488,322	554,752	0.1236	0.8764	20.11
78.5	3,926,564	335,598	0.0855	0.9145	17.63

PECO ENERGY COMPANY
ELECTRIC PLANT

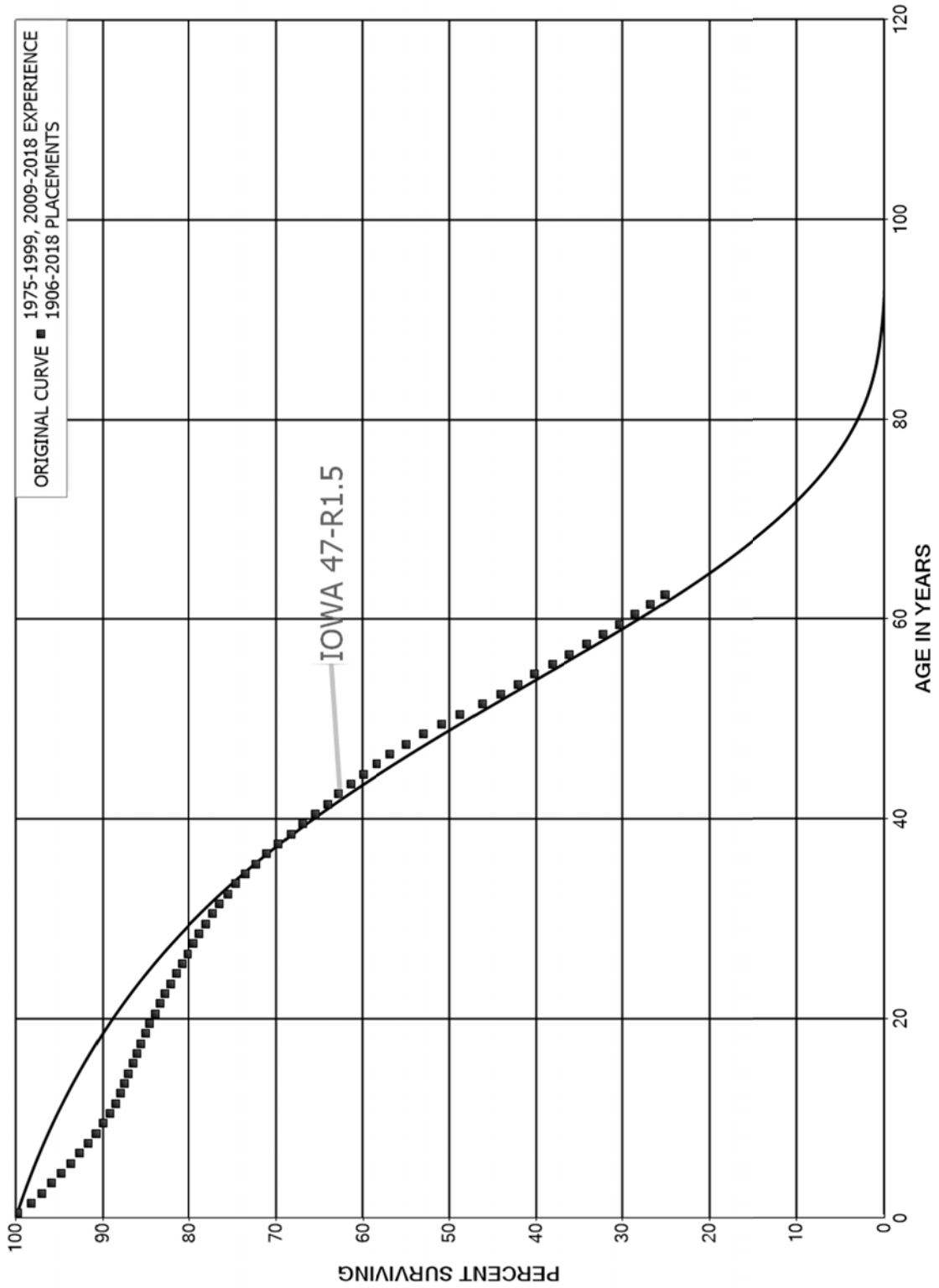
ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1898-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	3,555,484	563,271	0.1584	0.8416	16.12
80.5	2,956,997	323,449	0.1094	0.8906	13.57
81.5	2,592,201	261,253	0.1008	0.8992	12.08
82.5	2,326,043	222,108	0.0955	0.9045	10.86
83.5	2,091,296	210,217	0.1005	0.8995	9.83
84.5	1,822,022	165,000	0.0906	0.9094	8.84
85.5	1,584,137	158,135	0.0998	0.9002	8.04
86.5	1,344,068	133,348	0.0992	0.9008	7.24
87.5	1,092,936	117,384	0.1074	0.8926	6.52
88.5	822,419	91,628	0.1114	0.8886	5.82
89.5	627,258	72,103	0.1149	0.8851	5.17
90.5	448,482	52,662	0.1174	0.8826	4.58
91.5	286,341	58,299	0.2036	0.7964	4.04
92.5	130,040	20,898	0.1607	0.8393	3.22
93.5	12,309	2,404	0.1953	0.8047	2.70
94.5	8,016		0.0000	1.0000	2.17
95.5	8,016	7,255	0.9050	0.0950	2.17
96.5	761	761	1.0000		0.21
97.5					

PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 368 LINE TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 368 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1975-1999, 2009-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	488,186,469	1,565,857	0.0032	0.9968	100.00
0.5	470,478,661	7,213,155	0.0153	0.9847	99.68
1.5	458,437,882	5,411,946	0.0118	0.9882	98.15
2.5	435,000,380	5,108,436	0.0117	0.9883	96.99
3.5	423,863,570	5,059,041	0.0119	0.9881	95.85
4.5	397,589,046	4,487,377	0.0113	0.9887	94.71
5.5	381,093,744	4,344,151	0.0114	0.9886	93.64
6.5	369,052,876	3,806,276	0.0103	0.9897	92.57
7.5	367,436,715	3,433,348	0.0093	0.9907	91.62
8.5	338,952,946	3,017,579	0.0089	0.9911	90.76
9.5	318,683,711	2,822,891	0.0089	0.9911	89.95
10.5	293,264,133	2,124,163	0.0072	0.9928	89.16
11.5	276,651,355	1,869,560	0.0068	0.9932	88.51
12.5	260,442,964	1,361,953	0.0052	0.9948	87.91
13.5	247,292,331	1,192,451	0.0048	0.9952	87.45
14.5	238,430,846	1,313,550	0.0055	0.9945	87.03
15.5	236,712,374	1,346,213	0.0057	0.9943	86.55
16.5	230,330,915	1,262,834	0.0055	0.9945	86.06
17.5	209,115,606	1,212,362	0.0058	0.9942	85.59
18.5	222,132,456	1,381,682	0.0062	0.9938	85.09
19.5	228,428,042	1,504,866	0.0066	0.9934	84.56
20.5	227,078,049	1,631,159	0.0072	0.9928	84.01
21.5	221,584,833	1,602,560	0.0072	0.9928	83.40
22.5	222,650,674	1,740,447	0.0078	0.9922	82.80
23.5	218,043,819	1,706,038	0.0078	0.9922	82.15
24.5	210,375,050	1,626,212	0.0077	0.9923	81.51
25.5	197,978,902	1,652,994	0.0083	0.9917	80.88
26.5	185,790,164	1,537,277	0.0083	0.9917	80.20
27.5	175,542,729	1,559,640	0.0089	0.9911	79.54
28.5	158,255,189	1,516,581	0.0096	0.9904	78.83
29.5	134,583,942	1,393,570	0.0104	0.9896	78.08
30.5	112,413,299	1,183,738	0.0105	0.9895	77.27
31.5	94,174,131	1,153,831	0.0123	0.9877	76.46
32.5	79,542,792	965,842	0.0121	0.9879	75.52
33.5	68,854,316	1,043,069	0.0151	0.9849	74.60
34.5	66,004,657	1,089,123	0.0165	0.9835	73.47
35.5	66,364,473	1,099,408	0.0166	0.9834	72.26
36.5	63,339,637	1,206,177	0.0190	0.9810	71.06
37.5	61,340,393	1,239,260	0.0202	0.9798	69.71
38.5	63,294,137	1,274,655	0.0201	0.9799	68.30

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 368 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018			EXPERIENCE BAND 1975-1999, 2009-2018		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	68,516,859	1,482,770	0.0216	0.9784	66.93
40.5	69,589,553	1,445,158	0.0208	0.9792	65.48
41.5	68,230,865	1,420,871	0.0208	0.9792	64.12
42.5	66,067,971	1,419,296	0.0215	0.9785	62.78
43.5	61,841,584	1,473,770	0.0238	0.9762	61.43
44.5	54,455,246	1,422,170	0.0261	0.9739	59.97
45.5	47,633,376	1,317,387	0.0277	0.9723	58.40
46.5	42,884,509	1,418,963	0.0331	0.9669	56.79
47.5	38,479,662	1,372,570	0.0357	0.9643	54.91
48.5	31,964,341	1,299,180	0.0406	0.9594	52.95
49.5	22,371,537	909,824	0.0407	0.9593	50.80
50.5	16,019,152	823,799	0.0514	0.9486	48.73
51.5	13,198,406	625,428	0.0474	0.9526	46.23
52.5	12,466,721	550,885	0.0442	0.9558	44.04
53.5	12,284,350	569,101	0.0463	0.9537	42.09
54.5	12,034,316	608,709	0.0506	0.9494	40.14
55.5	11,180,937	608,873	0.0545	0.9455	38.11
56.5	10,563,476	586,809	0.0556	0.9444	36.03
57.5	9,715,788	535,373	0.0551	0.9449	34.03
58.5	8,526,108	489,651	0.0574	0.9426	32.16
59.5	7,600,162	460,943	0.0606	0.9394	30.31
60.5	6,711,651	406,876	0.0606	0.9394	28.47
61.5	5,766,307	360,018	0.0624	0.9376	26.75
62.5	4,570,555	299,646	0.0656	0.9344	25.08
63.5	3,521,331	231,227	0.0657	0.9343	23.43
64.5	2,705,463	178,397	0.0659	0.9341	21.89
65.5	2,112,203	143,429	0.0679	0.9321	20.45
66.5	1,645,591	124,547	0.0757	0.9243	19.06
67.5	1,336,058	130,022	0.0973	0.9027	17.62
68.5	1,046,707	145,082	0.1386	0.8614	15.90
69.5	786,278	110,316	0.1403	0.8597	13.70
70.5	577,815	85,023	0.1471	0.8529	11.78
71.5	450,896	90,383	0.2005	0.7995	10.04
72.5	326,836	83,306	0.2549	0.7451	8.03
73.5	239,217	58,165	0.2431	0.7569	5.98
74.5	185,471	38,905	0.2098	0.7902	4.53
75.5	139,299	21,418	0.1538	0.8462	3.58
76.5	114,772	28,040	0.2443	0.7557	3.03
77.5	94,642	21,551	0.2277	0.7723	2.29
78.5	78,570	22,204	0.2826	0.7174	1.77

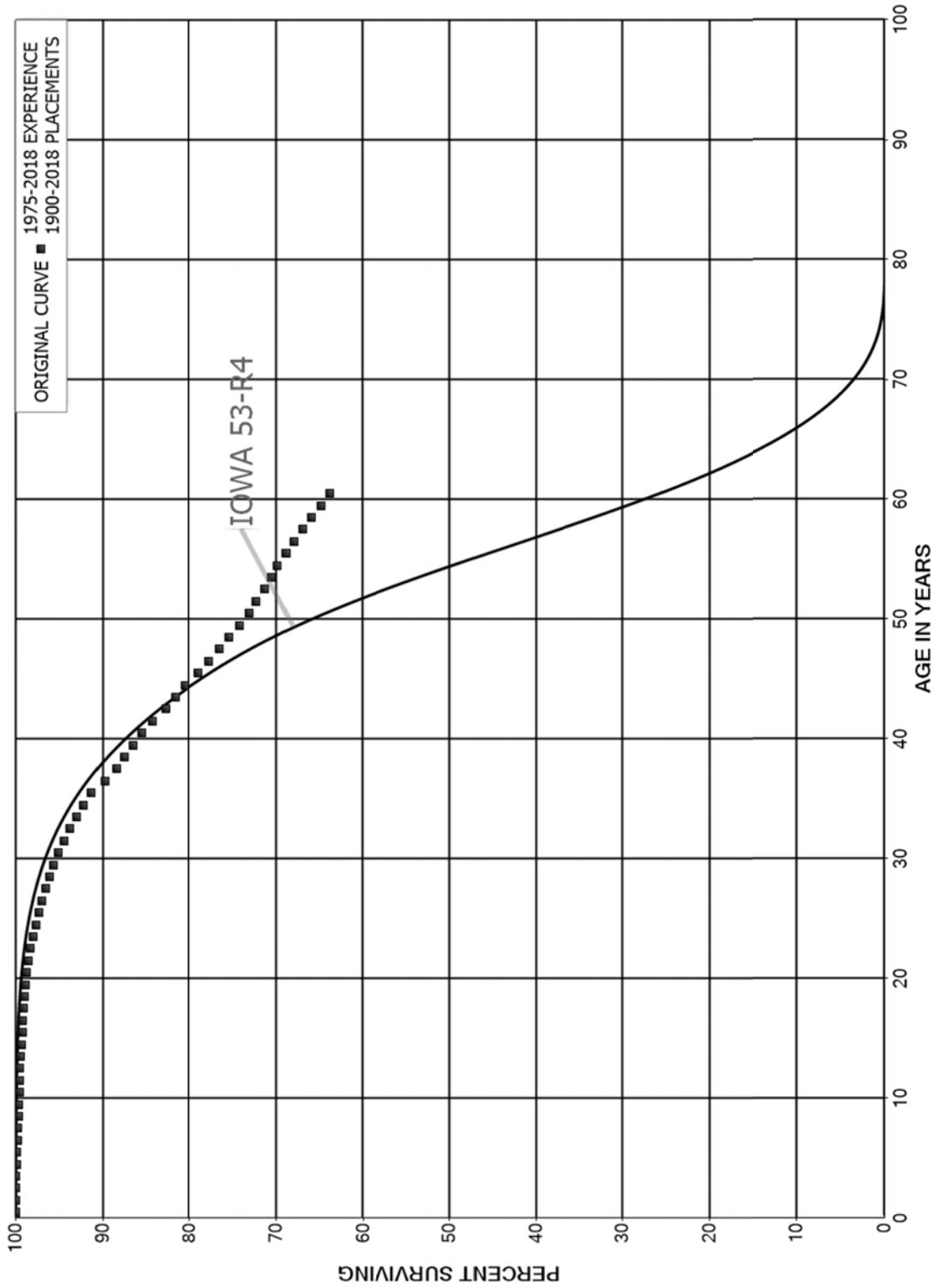
PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 368 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018			EXPERIENCE BAND 1975-1999, 2009-2018		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	73,997	21,582	0.2917	0.7083	1.27
80.5	56,832	18,622	0.3277	0.6723	0.90
81.5	43,571	15,039	0.3452	0.6548	0.60
82.5	27,668	11,354	0.4104	0.5896	0.40
83.5	17,965	9,149	0.5092	0.4908	0.23
84.5	16,927	7,178	0.4240	0.5760	0.11
85.5	13,742	4,316	0.3141	0.6859	0.07
86.5	9,806	4,394	0.4481	0.5519	0.05
87.5	5,393	3,355	0.6221	0.3779	0.02
88.5	2,032	1,254	0.6171	0.3829	0.01
89.5	767	407	0.5306	0.4694	0.00
90.5	358	176	0.4918	0.5082	0.00
91.5	752	338	0.4493	0.5507	0.00
92.5	413	183	0.4429	0.5571	0.00
93.5	229	138	0.6000	0.4000	0.00
94.5	97	68	0.6940	0.3060	0.00
95.5	42	22	0.5171	0.4829	0.00
96.5	19	10	0.5206	0.4794	0.00
97.5	9	4	0.4398	0.5602	0.00
98.5	5	2	0.3532	0.6468	0.00
99.5	3	1	0.2967	0.7033	0.00
100.5	2		0.0000	1.0000	0.00
101.5	2		0.0000	1.0000	0.00
102.5	2		0.0000	1.0000	0.00
103.5	2		0.0000	1.0000	0.00
104.5	1		0.0000	1.0000	0.00
105.5					0.00

PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 369.1 SERVICES - AERIAL
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 369.1 SERVICES - AERIAL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	143,373,885	17,756	0.0001	0.9999	100.00
0.5	136,829,762	39,629	0.0003	0.9997	99.99
1.5	131,818,950	49,146	0.0004	0.9996	99.96
2.5	126,581,334	39,336	0.0003	0.9997	99.92
3.5	123,184,865	50,452	0.0004	0.9996	99.89
4.5	119,937,006	70,837	0.0006	0.9994	99.85
5.5	117,390,691	53,743	0.0005	0.9995	99.79
6.5	114,545,408	62,794	0.0005	0.9995	99.74
7.5	111,416,721	59,031	0.0005	0.9995	99.69
8.5	107,957,202	42,048	0.0004	0.9996	99.64
9.5	95,703,027	41,189	0.0004	0.9996	99.60
10.5	93,418,668	43,838	0.0005	0.9995	99.56
11.5	92,841,900	53,665	0.0006	0.9994	99.51
12.5	89,062,372	87,853	0.0010	0.9990	99.45
13.5	86,441,340	59,512	0.0007	0.9993	99.35
14.5	81,350,397	50,457	0.0006	0.9994	99.28
15.5	77,698,836	48,237	0.0006	0.9994	99.22
16.5	70,657,192	59,335	0.0008	0.9992	99.16
17.5	62,692,178	66,938	0.0011	0.9989	99.08
18.5	61,103,064	83,400	0.0014	0.9986	98.97
19.5	58,683,094	94,579	0.0016	0.9984	98.84
20.5	56,319,310	116,856	0.0021	0.9979	98.68
21.5	53,180,240	126,591	0.0024	0.9976	98.47
22.5	51,798,673	127,477	0.0025	0.9975	98.24
23.5	48,763,261	176,619	0.0036	0.9964	98.00
24.5	47,153,539	182,044	0.0039	0.9961	97.64
25.5	45,341,825	164,218	0.0036	0.9964	97.27
26.5	43,703,858	184,596	0.0042	0.9958	96.91
27.5	42,047,893	196,010	0.0047	0.9953	96.50
28.5	39,962,120	189,541	0.0047	0.9953	96.05
29.5	37,484,101	190,600	0.0051	0.9949	95.60
30.5	35,325,784	255,589	0.0072	0.9928	95.11
31.5	33,205,001	247,686	0.0075	0.9925	94.42
32.5	31,221,889	270,255	0.0087	0.9913	93.72
33.5	29,466,979	221,138	0.0075	0.9925	92.91
34.5	27,668,856	270,415	0.0098	0.9902	92.21
35.5	26,109,062	444,930	0.0170	0.9830	91.31
36.5	24,342,541	354,328	0.0146	0.9854	89.75
37.5	23,034,345	244,186	0.0106	0.9894	88.45
38.5	21,341,216	234,240	0.0110	0.9890	87.51

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 369.1 SERVICES - AERIAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	19,877,130	248,639	0.0125	0.9875	86.55
40.5	18,400,348	249,061	0.0135	0.9865	85.47
41.5	16,941,270	319,873	0.0189	0.9811	84.31
42.5	15,558,747	207,953	0.0134	0.9866	82.72
43.5	14,275,403	196,976	0.0138	0.9862	81.61
44.5	12,976,748	240,070	0.0185	0.9815	80.49
45.5	11,764,198	194,044	0.0165	0.9835	79.00
46.5	10,760,787	158,950	0.0148	0.9852	77.69
47.5	9,877,011	142,183	0.0144	0.9856	76.55
48.5	8,842,021	145,735	0.0165	0.9835	75.44
49.5	7,724,585	115,495	0.0150	0.9850	74.20
50.5	6,902,952	72,148	0.0105	0.9895	73.09
51.5	6,198,590	86,343	0.0139	0.9861	72.33
52.5	5,449,349	62,056	0.0114	0.9886	71.32
53.5	4,943,270	50,964	0.0103	0.9897	70.51
54.5	4,214,763	55,065	0.0131	0.9869	69.78
55.5	3,575,412	45,417	0.0127	0.9873	68.87
56.5	3,048,612	45,786	0.0150	0.9850	67.99
57.5	2,579,540	39,213	0.0152	0.9848	66.97
58.5	2,165,921	36,455	0.0168	0.9832	65.96
59.5	1,699,119	26,280	0.0155	0.9845	64.85
60.5	1,241,402	29,280	0.0236	0.9764	63.84
61.5	825,500	19,339	0.0234	0.9766	62.34
62.5	388,755	11,956	0.0308	0.9692	60.88
63.5	100,967	11,902	0.1179	0.8821	59.00
64.5	85,524	3,630	0.0424	0.9576	52.05
65.5	63,961	3,537	0.0553	0.9447	49.84
66.5	4,908	829	0.1688	0.8312	47.08
67.5	4,080	1,032	0.2530	0.7470	39.13
68.5	3,048	874	0.2867	0.7133	29.23
69.5	2,174	809	0.3720	0.6280	20.85
70.5	1,365	1,210	0.8866	0.1134	13.10
71.5	155	108	0.6981	0.3019	1.49
72.5	47	42	0.9048	0.0952	0.45
73.5	4	4	1.0000		0.04
74.5	7,882		0.0000	1.0000	
75.5	7,882		0.0000		
76.5	7,882		0.0000		
77.5	7,882		0.0000		
78.5	7,882		0.0000		

PECO ENERGY COMPANY
ELECTRIC PLANT

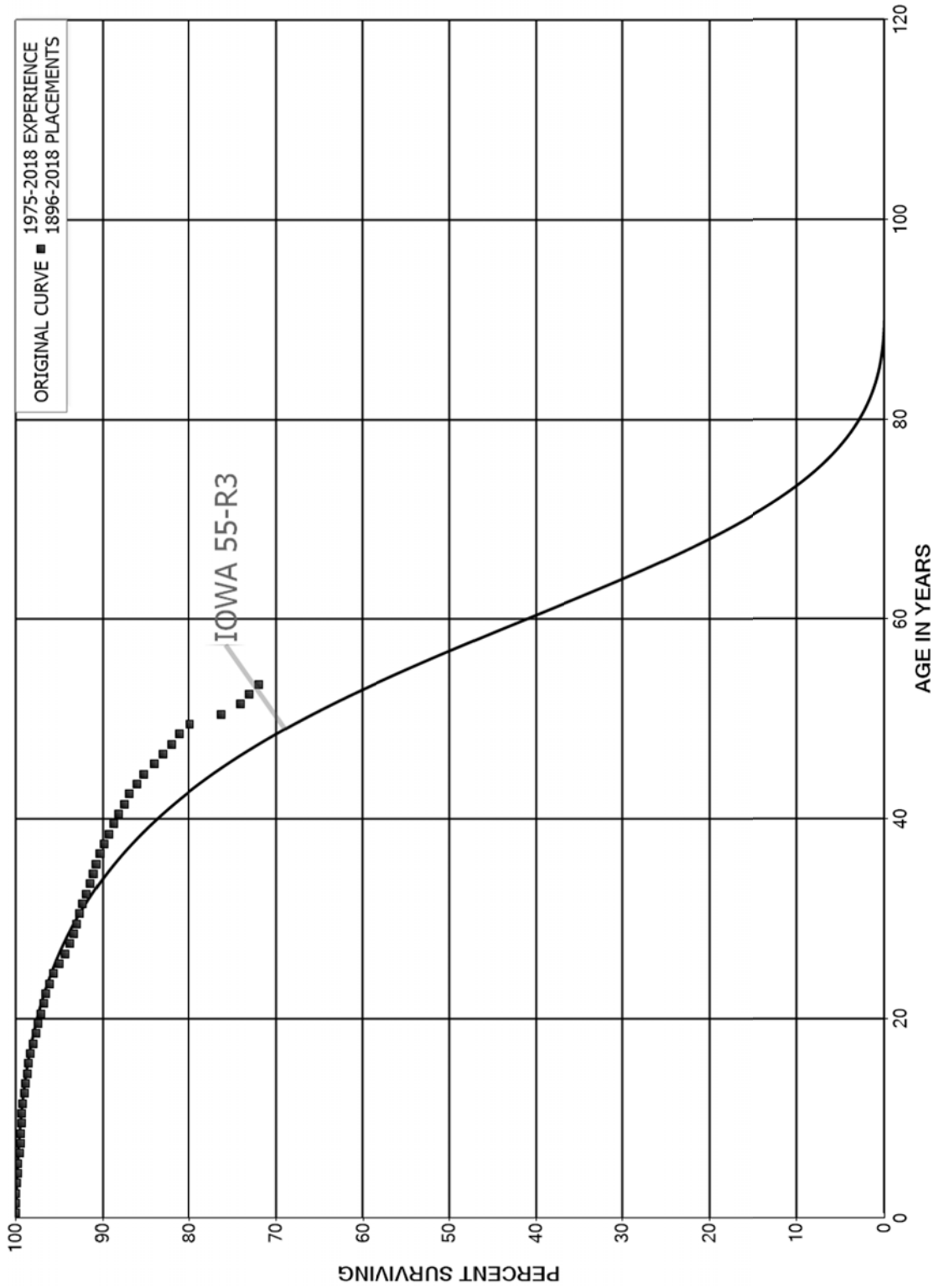
ACCOUNT 369.1 SERVICES - AERIAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	7,882		0.0000		
80.5	7,882		0.0000		
81.5	7,882		0.0000		
82.5	7,882		0.0000		
83.5	7,882		0.0000		
84.5	7,882		0.0000		
85.5	7,882		0.0000		
86.5	7,882		0.0000		
87.5	7,882		0.0000		
88.5	7,882		0.0000		
89.5	7,882		0.0000		
90.5	7,882	5,964	0.7567		
91.5	1,918		0.0000		
92.5	1,918	1,918	1.0000		
93.5					

PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 369.2 SERVICES - UNDERGROUND
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 369.2 SERVICES - UNDERGROUND

ORIGINAL LIFE TABLE

PLACEMENT BAND 1896-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	267,170,879	26,210	0.0001	0.9999	100.00
0.5	266,906,453	91,826	0.0003	0.9997	99.99
1.5	267,302,889	123,972	0.0005	0.9995	99.96
2.5	265,839,585	134,248	0.0005	0.9995	99.91
3.5	265,359,525	225,996	0.0009	0.9991	99.86
4.5	264,137,679	159,224	0.0006	0.9994	99.77
5.5	263,302,270	584,591	0.0022	0.9978	99.71
6.5	262,144,132	186,689	0.0007	0.9993	99.49
7.5	256,224,513	144,693	0.0006	0.9994	99.42
8.5	254,685,551	132,350	0.0005	0.9995	99.37
9.5	225,167,426	168,672	0.0007	0.9993	99.31
10.5	225,880,524	258,398	0.0011	0.9989	99.24
11.5	229,644,210	363,543	0.0016	0.9984	99.13
12.5	225,952,282	357,127	0.0016	0.9984	98.97
13.5	223,247,468	335,144	0.0015	0.9985	98.81
14.5	221,810,933	402,439	0.0018	0.9982	98.66
15.5	213,484,691	482,650	0.0023	0.9977	98.49
16.5	201,804,671	596,329	0.0030	0.9970	98.26
17.5	190,073,701	609,655	0.0032	0.9968	97.97
18.5	188,503,198	589,271	0.0031	0.9969	97.66
19.5	178,679,473	536,966	0.0030	0.9970	97.35
20.5	172,691,783	561,745	0.0033	0.9967	97.06
21.5	162,881,396	466,677	0.0029	0.9971	96.74
22.5	158,592,528	667,906	0.0042	0.9958	96.47
23.5	148,479,298	651,625	0.0044	0.9956	96.06
24.5	142,529,144	1,058,312	0.0074	0.9926	95.64
25.5	131,411,010	922,028	0.0070	0.9930	94.93
26.5	122,143,821	727,235	0.0060	0.9940	94.26
27.5	113,912,019	521,982	0.0046	0.9954	93.70
28.5	103,062,119	360,995	0.0035	0.9965	93.27
29.5	92,041,384	345,169	0.0038	0.9962	92.95
30.5	80,354,705	318,159	0.0040	0.9960	92.60
31.5	68,796,574	323,205	0.0047	0.9953	92.23
32.5	58,772,912	224,193	0.0038	0.9962	91.80
33.5	50,656,690	229,150	0.0045	0.9955	91.45
34.5	42,942,414	156,063	0.0036	0.9964	91.03
35.5	37,059,218	174,666	0.0047	0.9953	90.70
36.5	33,924,727	178,854	0.0053	0.9947	90.28
37.5	28,809,764	174,465	0.0061	0.9939	89.80
38.5	23,752,667	141,788	0.0060	0.9940	89.26

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 369.2 SERVICES - UNDERGROUND

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1896-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	19,219,493	110,223	0.0057	0.9943	88.72
40.5	14,942,679	120,706	0.0081	0.9919	88.21
41.5	12,360,017	78,640	0.0064	0.9936	87.50
42.5	10,267,732	98,780	0.0096	0.9904	86.94
43.5	8,783,468	84,909	0.0097	0.9903	86.11
44.5	7,229,337	99,691	0.0138	0.9862	85.28
45.5	5,545,174	70,917	0.0128	0.9872	84.10
46.5	4,858,889	54,864	0.0113	0.9887	83.02
47.5	4,375,665	49,906	0.0114	0.9886	82.09
48.5	4,039,771	60,415	0.0150	0.9850	81.15
49.5	3,737,357	171,236	0.0458	0.9542	79.94
50.5	3,308,651	94,681	0.0286	0.9714	76.27
51.5	3,020,488	43,278	0.0143	0.9857	74.09
52.5	2,748,819	41,341	0.0150	0.9850	73.03
53.5	2,480,558	37,709	0.0152	0.9848	71.93
54.5	2,288,992	35,588	0.0155	0.9845	70.84
55.5	2,155,941	43,215	0.0200	0.9800	69.74
56.5	1,950,048	40,597	0.0208	0.9792	68.34
57.5	1,721,150	29,094	0.0169	0.9831	66.92
58.5	1,527,777	30,294	0.0198	0.9802	65.79
59.5	1,396,753	59,832	0.0428	0.9572	64.48
60.5	1,290,225	30,815	0.0239	0.9761	61.72
61.5	1,192,443	34,111	0.0286	0.9714	60.24
62.5	1,067,674	29,557	0.0277	0.9723	58.52
63.5	975,584	81,067	0.0831	0.9169	56.90
64.5	802,844	34,847	0.0434	0.9566	52.17
65.5	662,294	117,504	0.1774	0.8226	49.91
66.5	512,346	166,868	0.3257	0.6743	41.05
67.5	345,863	56,018	0.1620	0.8380	27.68
68.5	290,634	12,001	0.0413	0.9587	23.20
69.5	236,775	15,400	0.0650	0.9350	22.24
70.5	190,122	19,057	0.1002	0.8998	20.79
71.5	149,312	13,867	0.0929	0.9071	18.71
72.5	116,935	11,134	0.0952	0.9048	16.97
73.5	100,353	10,799	0.1076	0.8924	15.36
74.5	189,217	11,112	0.0587	0.9413	13.70
75.5	176,816	7,507	0.0425	0.9575	12.90
76.5	163,847	2,478	0.0151	0.9849	12.35
77.5	149,495	1,695	0.0113	0.9887	12.16
78.5	140,551	1,584	0.0113	0.9887	12.03

PECO ENERGY COMPANY
ELECTRIC PLANT

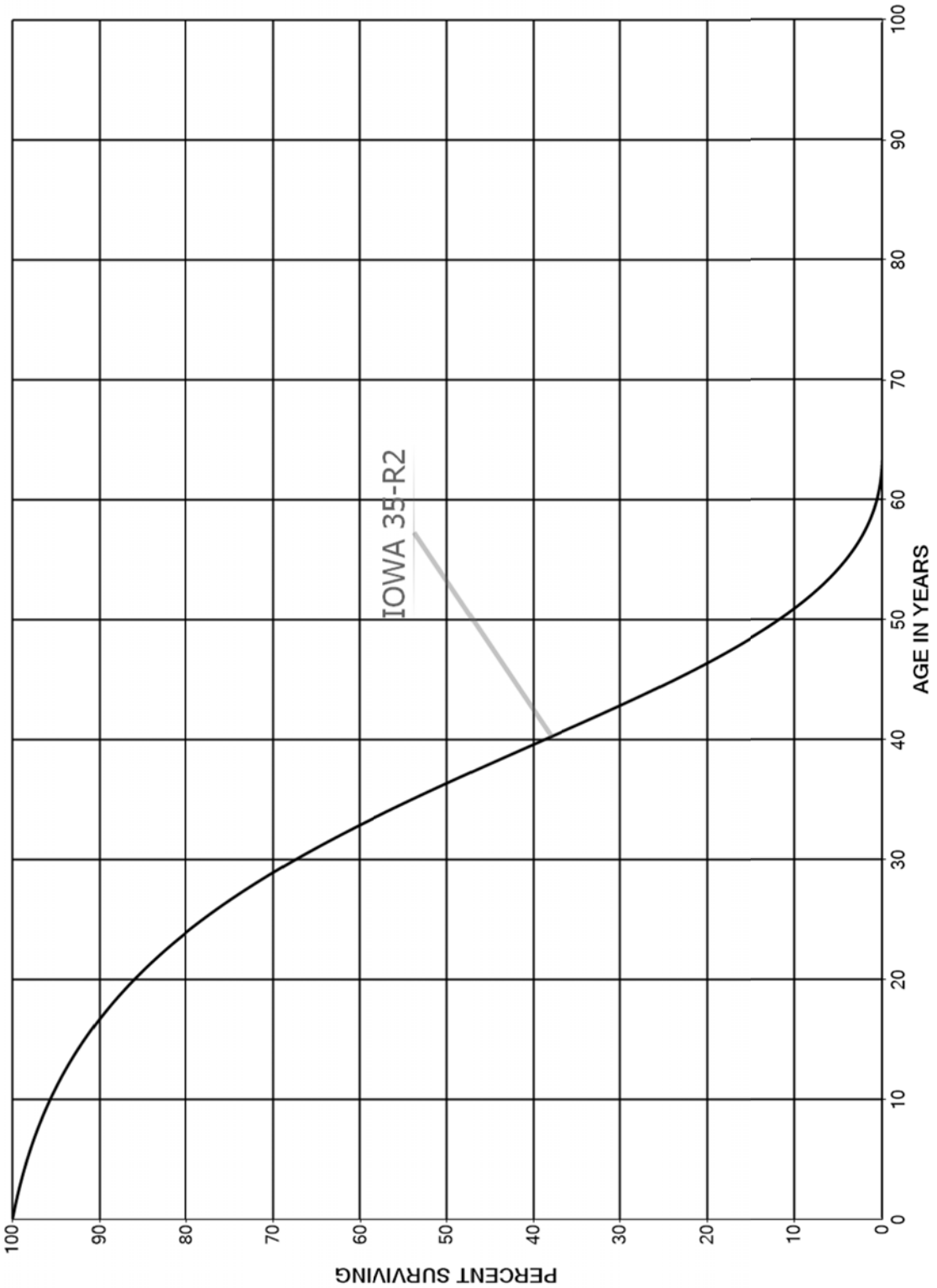
ACCOUNT 369.2 SERVICES - UNDERGROUND

ORIGINAL LIFE TABLE, CONT.

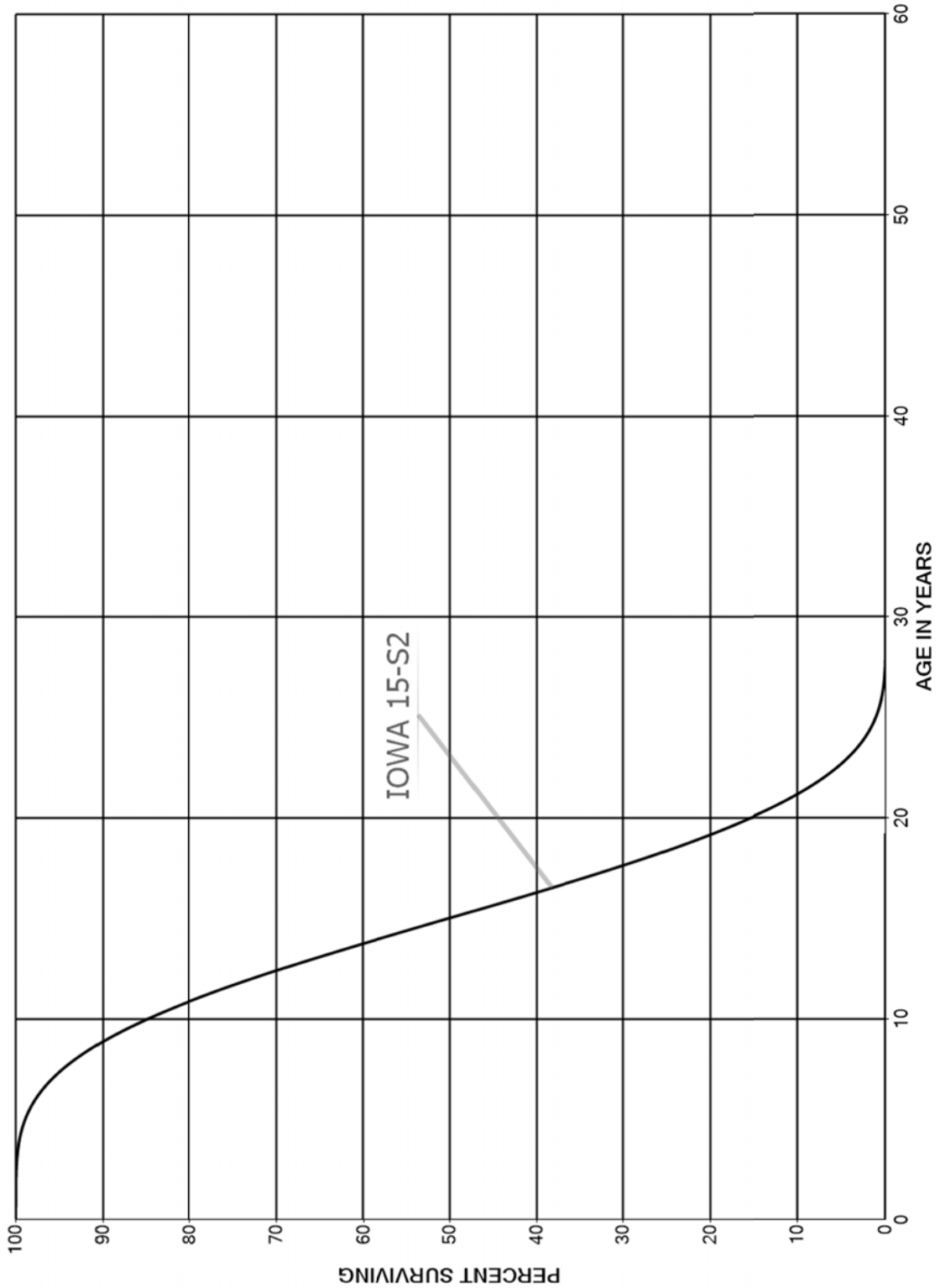
PLACEMENT BAND 1896-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	138,967	2,064	0.0149	0.9851	11.89
80.5	136,903	2,385	0.0174	0.9826	11.71
81.5	134,518	646	0.0048	0.9952	11.51
82.5	133,872	9,691	0.0724	0.9276	11.46
83.5	124,181	6,742	0.0543	0.9457	10.63
84.5	117,439	6,172	0.0526	0.9474	10.05
85.5	111,267	6,020	0.0541	0.9459	9.52
86.5	105,247	1,097	0.0104	0.9896	9.01
87.5	104,150	17	0.0002	0.9998	8.91
88.5	104,133	4	0.0000	1.0000	8.91
89.5	104,130		0.0000	1.0000	8.91
90.5	104,130	1,535	0.0147	0.9853	8.91
91.5	102,595		0.0000	1.0000	8.78
92.5	102,595	8,716	0.0850	0.9150	8.78
93.5	93,879	11,641	0.1240	0.8760	8.03
94.5	82,238	24,061	0.2926	0.7074	7.04
95.5	58,177	25,591	0.4399	0.5601	4.98
96.5	32,586	32,586	1.0000		2.79
97.5					

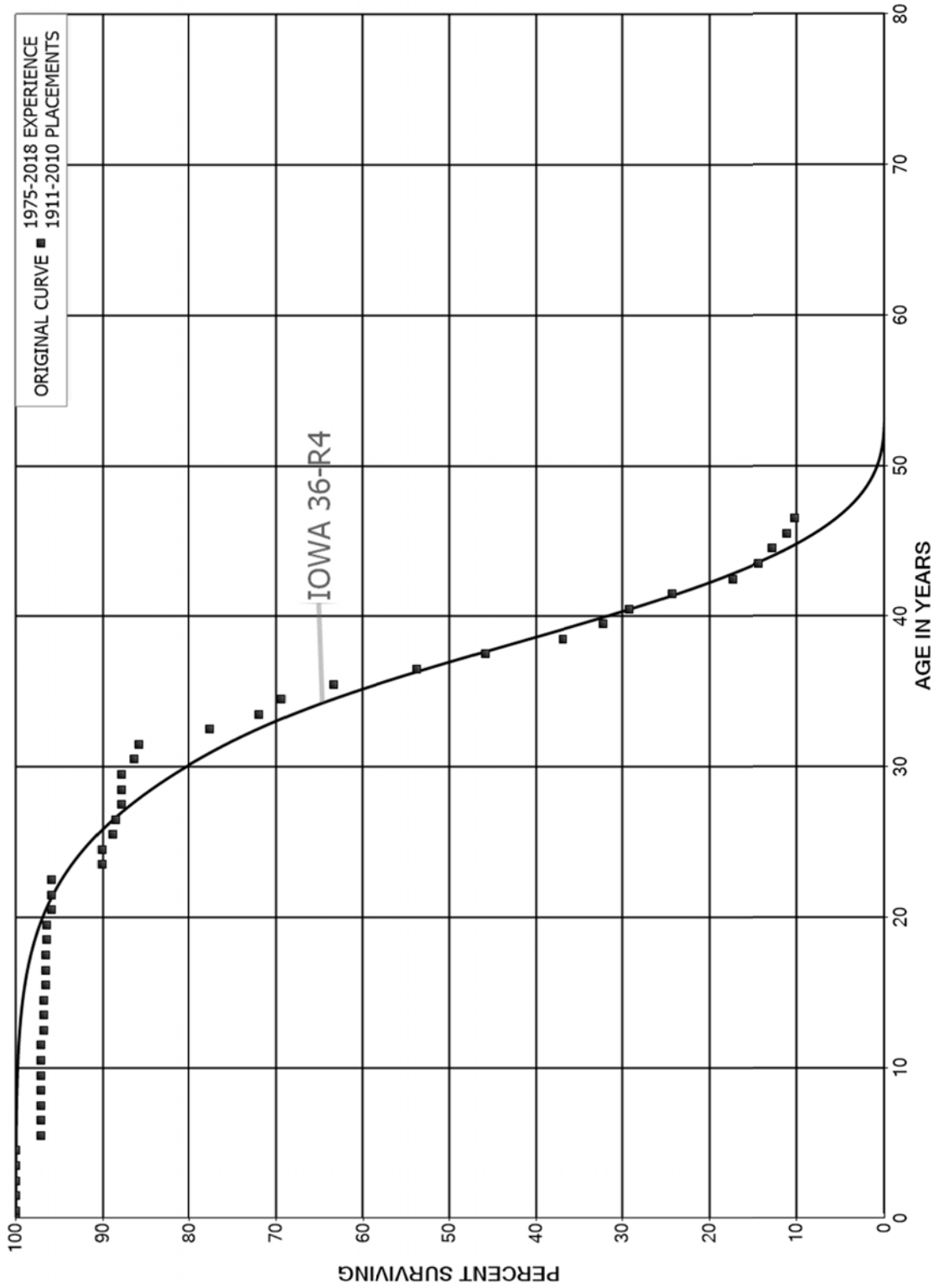
PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 370.1 METER TRANSFORMERS
SMOOTH SURVIVOR CURVE



PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 370.2 SMART METERS
SMOOTH SURVIVOR CURVE



PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1911-2010 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,710,593		0.0000	1.0000	100.00
0.5	3,710,593		0.0000	1.0000	100.00
1.5	1,078,447		0.0000	1.0000	100.00
2.5	1,078,447		0.0000	1.0000	100.00
3.5	1,078,447		0.0000	1.0000	100.00
4.5	1,080,509	31,513	0.0292	0.9708	100.00
5.5	1,050,974		0.0000	1.0000	97.08
6.5	1,052,552		0.0000	1.0000	97.08
7.5	1,059,537		0.0000	1.0000	97.08
8.5	1,074,590		0.0000	1.0000	97.08
9.5	1,082,318		0.0000	1.0000	97.08
10.5	1,102,777		0.0000	1.0000	97.08
11.5	1,131,693	4,811	0.0043	0.9957	97.08
12.5	1,152,862		0.0000	1.0000	96.67
13.5	1,186,315		0.0000	1.0000	96.67
14.5	1,205,475	1,855	0.0015	0.9985	96.67
15.5	1,212,590		0.0000	1.0000	96.52
16.5	1,227,368		0.0000	1.0000	96.52
17.5	1,252,367	1,982	0.0016	0.9984	96.52
18.5	1,259,556		0.0000	1.0000	96.37
19.5	1,109,053	6,573	0.0059	0.9941	96.37
20.5	366,370		0.0000	1.0000	95.80
21.5	321,771		0.0000	1.0000	95.80
22.5	316,766	18,874	0.0596	0.9404	95.80
23.5	264,923		0.0000	1.0000	90.09
24.5	263,418	3,733	0.0142	0.9858	90.09
25.5	259,764	999	0.0038	0.9962	88.81
26.5	258,765	1,728	0.0067	0.9933	88.47
27.5	260,124		0.0000	1.0000	87.88
28.5	261,501		0.0000	1.0000	87.88
29.5	261,501	4,510	0.0172	0.9828	87.88
30.5	257,040	1,578	0.0061	0.9939	86.37
31.5	255,608	24,496	0.0958	0.9042	85.84
32.5	232,121	16,972	0.0731	0.9269	77.61
33.5	216,776	7,729	0.0357	0.9643	71.93
34.5	209,048	18,106	0.0866	0.9134	69.37
35.5	191,008	28,916	0.1514	0.8486	63.36
36.5	162,469	23,998	0.1477	0.8523	53.77
37.5	138,471	27,170	0.1962	0.8038	45.83
38.5	111,746	14,289	0.1279	0.8721	36.84

PECO ENERGY COMPANY
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ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2010 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	97,457	8,971	0.0920	0.9080	32.13
40.5	88,716	14,778	0.1666	0.8334	29.17
41.5	73,939	21,266	0.2876	0.7124	24.31
42.5	52,881	9,172	0.1734	0.8266	17.32
43.5	53,686	5,898	0.1099	0.8901	14.31
44.5	50,658	6,466	0.1276	0.8724	12.74
45.5	48,552	4,162	0.0857	0.9143	11.12
46.5	46,233	17,555	0.3797	0.6203	10.16
47.5	30,071	3,336	0.1109	0.8891	6.30
48.5	27,364	51	0.0019	0.9981	5.60
49.5	28,233	79	0.0028	0.9972	5.59
50.5	32,442	8,709	0.2684	0.7316	5.58
51.5	24,680	628	0.0254	0.9746	4.08
52.5	24,154	1,376	0.0570	0.9430	3.98
53.5	23,561		0.0000	1.0000	3.75
54.5	23,561	1,542	0.0654	0.9346	3.75
55.5	22,084	146	0.0066	0.9934	3.51
56.5	21,938	1,009	0.0460	0.9540	3.48
57.5	21,017	1,628	0.0775	0.9225	3.32
58.5	19,413		0.0000	1.0000	3.06
59.5	19,413	67	0.0034	0.9966	3.06
60.5	19,406	377	0.0194	0.9806	3.05
61.5	19,029		0.0000	1.0000	2.99
62.5	19,029	444	0.0234	0.9766	2.99
63.5	18,708		0.0000	1.0000	2.92
64.5	18,708	230	0.0123	0.9877	2.92
65.5	18,479		0.0000	1.0000	2.89
66.5	18,479	208	0.0113	0.9887	2.89
67.5	18,271	1,268	0.0694	0.9306	2.86
68.5	17,002	1,378	0.0810	0.9190	2.66
69.5	15,624	4,360	0.2790	0.7210	2.44
70.5	11,265	1,843	0.1636	0.8364	1.76
71.5	9,421	1,393	0.1478	0.8522	1.47
72.5	8,029	629	0.0784	0.9216	1.26
73.5	7,400	920	0.1243	0.8757	1.16
74.5	6,480	4,288	0.6617	0.3383	1.01
75.5	2,192	947	0.4320	0.5680	0.34
76.5	1,245	101	0.0813	0.9187	0.19
77.5	1,144	784	0.6853	0.3147	0.18
78.5	360		0.0000	1.0000	0.06

PECO ENERGY COMPANY
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ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2010 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	360	64	0.1790	0.8210	0.06
80.5	295		0.0000	1.0000	0.05
81.5	295	88	0.2977	0.7023	0.05
82.5	207	24	0.1153	0.8847	0.03
83.5	184		0.0000	1.0000	0.03
84.5	184	60	0.3261	0.6739	0.03
85.5	124		0.0000	1.0000	0.02
86.5	124		0.0000	1.0000	0.02
87.5	124	124	1.0000		0.02
88.5					

PECO ENERGY COMPANY
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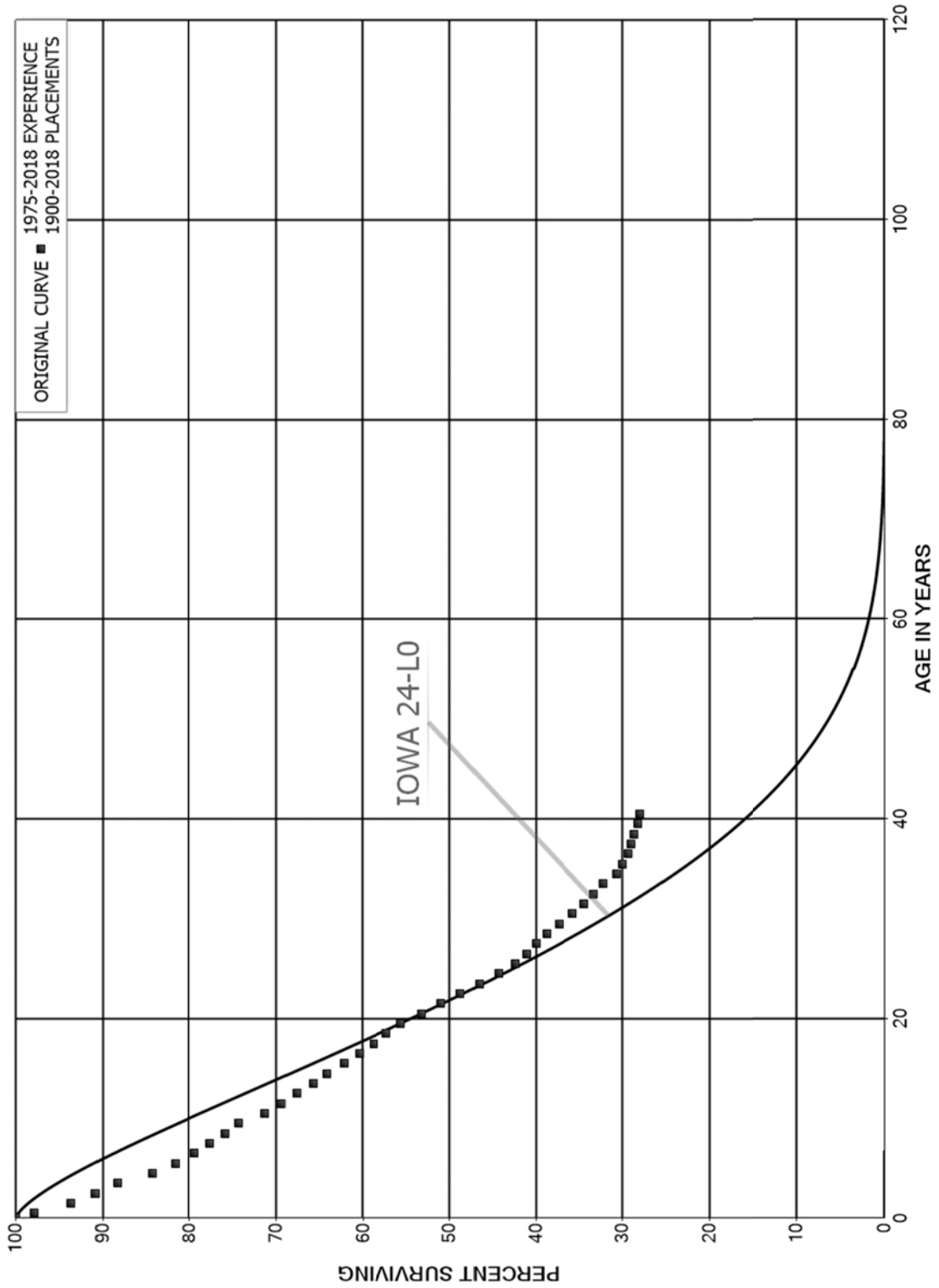
ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	93,863,075	2,026,240	0.0216	0.9784	100.00
0.5	90,548,074	3,870,376	0.0427	0.9573	97.84
1.5	80,809,698	2,480,414	0.0307	0.9693	93.66
2.5	78,180,481	2,197,516	0.0281	0.9719	90.78
3.5	75,955,241	3,365,466	0.0443	0.9557	88.23
4.5	72,513,616	2,335,496	0.0322	0.9678	84.32
5.5	70,251,884	1,863,634	0.0265	0.9735	81.61
6.5	68,172,181	1,604,903	0.0235	0.9765	79.44
7.5	66,540,797	1,472,972	0.0221	0.9779	77.57
8.5	64,859,023	1,348,077	0.0208	0.9792	75.85
9.5	43,328,070	1,740,281	0.0402	0.9598	74.28
10.5	54,113,932	1,470,693	0.0272	0.9728	71.29
11.5	57,163,175	1,445,429	0.0253	0.9747	69.36
12.5	57,833,505	1,594,244	0.0276	0.9724	67.60
13.5	58,433,192	1,379,588	0.0236	0.9764	65.74
14.5	57,115,038	1,837,268	0.0322	0.9678	64.19
15.5	54,158,274	1,547,763	0.0286	0.9714	62.12
16.5	52,376,502	1,377,468	0.0263	0.9737	60.35
17.5	49,139,533	1,242,181	0.0253	0.9747	58.76
18.5	48,048,109	1,388,830	0.0289	0.9711	57.28
19.5	37,696,015	1,620,855	0.0430	0.9570	55.62
20.5	23,967,636	1,045,596	0.0436	0.9564	53.23
21.5	18,889,121	796,523	0.0422	0.9578	50.91
22.5	16,217,763	764,376	0.0471	0.9529	48.76
23.5	13,632,988	646,155	0.0474	0.9526	46.46
24.5	12,566,390	536,551	0.0427	0.9573	44.26
25.5	11,623,410	350,470	0.0302	0.9698	42.37
26.5	10,861,341	306,064	0.0282	0.9718	41.09
27.5	10,082,253	293,718	0.0291	0.9709	39.93
28.5	9,123,839	344,257	0.0377	0.9623	38.77
29.5	8,307,562	358,685	0.0432	0.9568	37.31
30.5	7,259,751	259,739	0.0358	0.9642	35.70
31.5	6,587,515	207,389	0.0315	0.9685	34.42
32.5	6,108,755	217,634	0.0356	0.9644	33.34
33.5	5,128,307	236,303	0.0461	0.9539	32.15
34.5	4,274,101	104,788	0.0245	0.9755	30.67
35.5	3,575,584	68,890	0.0193	0.9807	29.92
36.5	3,105,512	45,748	0.0147	0.9853	29.34
37.5	2,788,481	28,886	0.0104	0.9896	28.91
38.5	2,515,381	34,836	0.0138	0.9862	28.61

PECO ENERGY COMPANY
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ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,135,899	23,794	0.0111	0.9889	28.21
40.5	1,834,738	37,174	0.0203	0.9797	27.90
41.5	1,473,211	24,658	0.0167	0.9833	27.33
42.5	1,176,198	12,015	0.0102	0.9898	26.87
43.5	998,341	15,374	0.0154	0.9846	26.60
44.5	814,011	16,631	0.0204	0.9796	26.19
45.5	632,506	16,753	0.0265	0.9735	25.65
46.5	453,260	20,245	0.0447	0.9553	24.98
47.5	349,768	22,983	0.0657	0.9343	23.86
48.5	296,501	12,143	0.0410	0.9590	22.29
49.5	266,067	24,074	0.0905	0.9095	21.38
50.5	227,442	16,312	0.0717	0.9283	19.44
51.5	196,366	16,203	0.0825	0.9175	18.05
52.5	165,495	12,703	0.0768	0.9232	16.56
53.5	146,309	13,602	0.0930	0.9070	15.29
54.5	128,979	8,821	0.0684	0.9316	13.87
55.5	109,973	5,405	0.0491	0.9509	12.92
56.5	100,443	5,331	0.0531	0.9469	12.28
57.5	97,208	6,716	0.0691	0.9309	11.63
58.5	83,373	4,268	0.0512	0.9488	10.83
59.5	69,461	2,013	0.0290	0.9710	10.27
60.5	81,374	5,306	0.0652	0.9348	9.98
61.5	79,697	3,284	0.0412	0.9588	9.33
62.5	77,931	10,415	0.1336	0.8664	8.94
63.5	69,714	2,551	0.0366	0.9634	7.75
64.5	67,163	9,859	0.1468	0.8532	7.46
65.5	58,698	2,579	0.0439	0.9561	6.37
66.5	65,828	1,692	0.0257	0.9743	6.09
67.5	81,223	1,766	0.0217	0.9783	5.93
68.5	83,284	7,942	0.0954	0.9046	5.80
69.5	75,342	21,288	0.2825	0.7175	5.25
70.5	54,054	5,451	0.1008	0.8992	3.77
71.5	48,603	1,085	0.0223	0.9777	3.39
72.5	47,518	663	0.0140	0.9860	3.31
73.5	46,855	1,508	0.0322	0.9678	3.26
74.5	55,123	3,323	0.0603	0.9397	3.16
75.5	51,801	1,010	0.0195	0.9805	2.97
76.5	50,791	2,568	0.0506	0.9494	2.91
77.5	48,223	1,185	0.0246	0.9754	2.76
78.5	47,038	270	0.0057	0.9943	2.70

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	46,768	311	0.0066	0.9934	2.68
80.5	46,457		0.0000	1.0000	2.66
81.5	46,457	1,057	0.0228	0.9772	2.66
82.5	45,400	32	0.0007	0.9993	2.60
83.5	45,368		0.0000	1.0000	2.60
84.5	45,368		0.0000	1.0000	2.60
85.5	45,368		0.0000	1.0000	2.60
86.5	45,368		0.0000	1.0000	2.60
87.5	45,368		0.0000	1.0000	2.60
88.5	45,368	1	0.0000	1.0000	2.60
89.5	45,367	99	0.0022	0.9978	2.60
90.5	45,268	4,389	0.0970	0.9030	2.59
91.5	40,879	8,281	0.2026	0.7974	2.34
92.5	32,598	13,356	0.4097	0.5903	1.87
93.5	19,242	6,267	0.3257	0.6743	1.10
94.5	12,975	5,323	0.4102	0.5898	0.74
95.5	7,652	4,033	0.5271	0.4729	0.44
96.5	3,619	2,432	0.6719	0.3281	0.21
97.5	1,187	481	0.4048	0.5952	0.07
98.5	707	635	0.8989	0.1011	0.04
99.5	71	60	0.8508	0.1492	0.00
100.5	10	7	0.7724	0.2276	0.00
101.5	2		0.0000	1.0000	0.00
102.5	1		0.0000	1.0000	0.00
103.5	0		0.0000	1.0000	0.00
104.5					0.00

PECO ENERGY COMPANY
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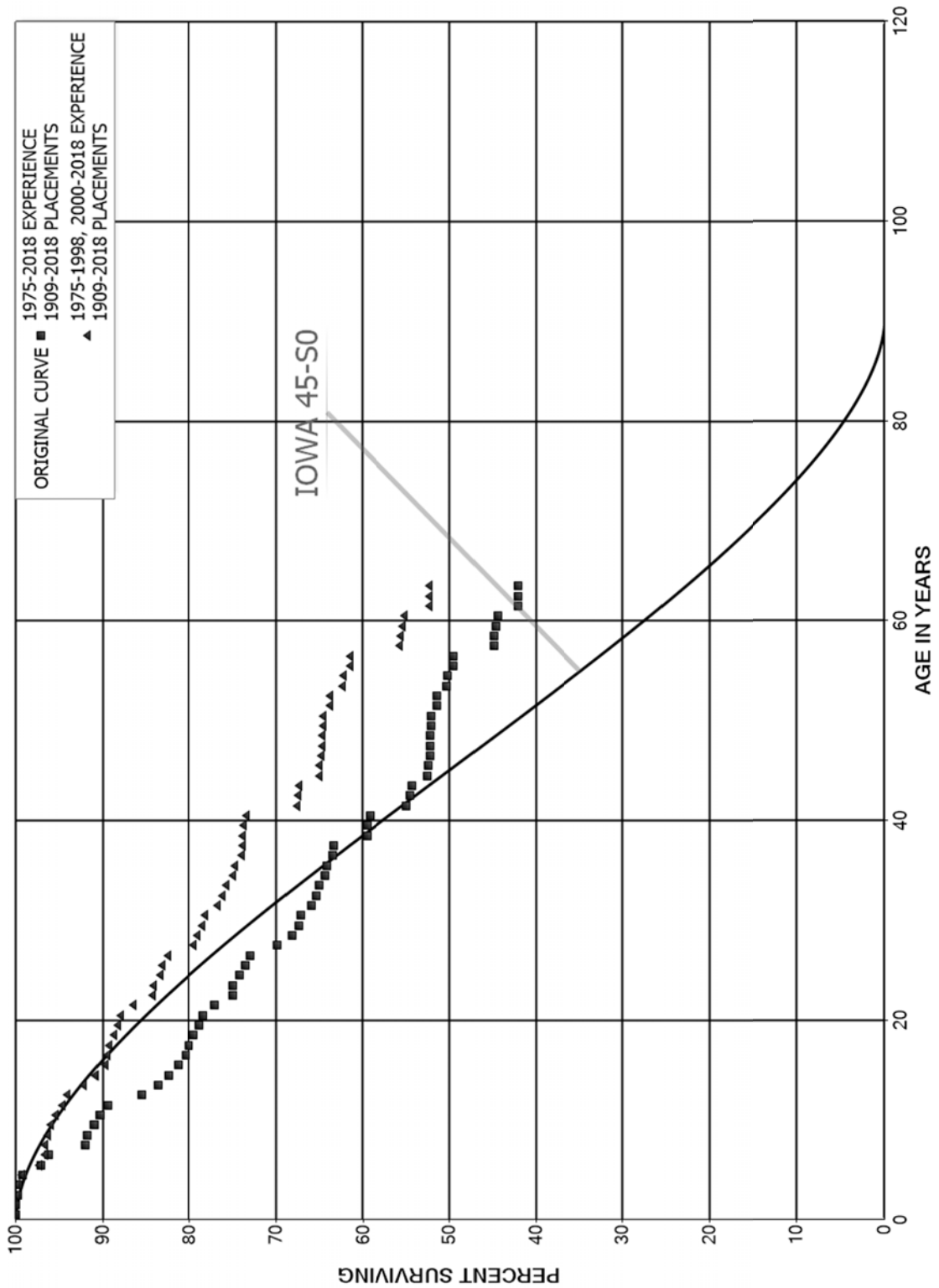
ACCOUNT 390 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1909-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	47,607,787		0.0000	1.0000	100.00
0.5	49,031,079		0.0000	1.0000	100.00
1.5	46,631,112	105,165	0.0023	0.9977	100.00
2.5	46,006,651	41,469	0.0009	0.9991	99.77
3.5	44,138,967	227,902	0.0052	0.9948	99.68
4.5	42,295,583	875,908	0.0207	0.9793	99.17
5.5	43,580,824	398,839	0.0092	0.9908	97.12
6.5	40,486,564	1,798,460	0.0444	0.9556	96.23
7.5	37,954,025	102,928	0.0027	0.9973	91.95
8.5	31,540,987	253,953	0.0081	0.9919	91.70
9.5	30,707,927	241,453	0.0079	0.9921	90.97
10.5	30,324,839	302,872	0.0100	0.9900	90.25
11.5	30,170,980	1,307,398	0.0433	0.9567	89.35
12.5	33,809,279	718,307	0.0212	0.9788	85.48
13.5	33,879,513	493,230	0.0146	0.9854	83.66
14.5	33,420,892	474,202	0.0142	0.9858	82.44
15.5	29,085,594	328,158	0.0113	0.9887	81.27
16.5	29,426,890	121,604	0.0041	0.9959	80.36
17.5	27,293,898	184,273	0.0068	0.9932	80.02
18.5	27,078,995	237,779	0.0088	0.9912	79.48
19.5	26,581,530	122,078	0.0046	0.9954	78.79
20.5	18,920,521	322,411	0.0170	0.9830	78.42
21.5	18,541,962	507,225	0.0274	0.9726	77.09
22.5	17,651,427	15,860	0.0009	0.9991	74.98
23.5	16,455,967	171,387	0.0104	0.9896	74.91
24.5	16,143,771	124,873	0.0077	0.9923	74.13
25.5	14,244,002	114,853	0.0081	0.9919	73.56
26.5	11,736,611	496,768	0.0423	0.9577	72.96
27.5	11,253,039	273,620	0.0243	0.9757	69.88
28.5	10,800,055	125,161	0.0116	0.9884	68.18
29.5	10,151,480	38,437	0.0038	0.9962	67.39
30.5	9,788,085	180,912	0.0185	0.9815	67.13
31.5	9,299,500	66,198	0.0071	0.9929	65.89
32.5	7,750,882	46,145	0.0060	0.9940	65.42
33.5	7,102,334	72,736	0.0102	0.9898	65.03
34.5	6,646,436	23,409	0.0035	0.9965	64.37
35.5	6,430,322	64,477	0.0100	0.9900	64.14
36.5	5,988,259	12,019	0.0020	0.9980	63.50
37.5	5,858,985	352,826	0.0602	0.9398	63.37
38.5	4,992,357	2,313	0.0005	0.9995	59.55

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ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,967,972	29,569	0.0060	0.9940	59.53
40.5	4,926,107	347,590	0.0706	0.9294	59.17
41.5	5,125,288	47,809	0.0093	0.9907	55.00
42.5	5,239,730	13,794	0.0026	0.9974	54.48
43.5	5,225,786	178,843	0.0342	0.9658	54.34
44.5	3,944,279	4,075	0.0010	0.9990	52.48
45.5	3,948,015	15,297	0.0039	0.9961	52.43
46.5	3,954,388	6,218	0.0016	0.9984	52.22
47.5	3,957,952	271	0.0001	0.9999	52.14
48.5	3,955,828	4,053	0.0010	0.9990	52.14
49.5	1,025,663	941	0.0009	0.9991	52.08
50.5	1,010,274	11,801	0.0117	0.9883	52.04
51.5	1,016,381	932	0.0009	0.9991	51.43
52.5	1,006,984	22,365	0.0222	0.9778	51.38
53.5	986,612	719	0.0007	0.9993	50.24
54.5	960,977	12,869	0.0134	0.9866	50.20
55.5	3,262,315		0.0000	1.0000	49.53
56.5	3,127,592	293,501	0.0938	0.9062	49.53
57.5	2,776,655	2,518	0.0009	0.9991	44.88
58.5	2,767,808	14,643	0.0053	0.9947	44.84
59.5	2,735,017	10,268	0.0038	0.9962	44.60
60.5	2,216,860	115,678	0.0522	0.9478	44.44
61.5	2,100,024	414	0.0002	0.9998	42.12
62.5	2,088,614	101	0.0000	1.0000	42.11
63.5	305,468		0.0000	1.0000	42.11
64.5	304,037	3,350	0.0110	0.9890	42.11
65.5	304,575	215,824	0.7086	0.2914	41.64
66.5	87,682	3,889	0.0443	0.9557	12.13
67.5	82,417		0.0000	1.0000	11.60
68.5	76,277		0.0000	1.0000	11.60
69.5	61,463	681	0.0111	0.9889	11.60
70.5	60,566	61	0.0010	0.9990	11.47
71.5	60,505	4,669	0.0772	0.9228	11.46
72.5	36,257		0.0000	1.0000	10.57
73.5	36,257	182	0.0050	0.9950	10.57
74.5	36,075		0.0000	1.0000	10.52
75.5	36,075		0.0000	1.0000	10.52
76.5	36,075		0.0000	1.0000	10.52
77.5	35,920	834	0.0232	0.9768	10.52
78.5	35,085		0.0000	1.0000	10.28

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	35,062		0.0000	1.0000	10.28
80.5	35,062		0.0000	1.0000	10.28
81.5	35,062	202	0.0058	0.9942	10.28
82.5	34,860		0.0000	1.0000	10.22
83.5	20,832		0.0000	1.0000	10.22
84.5	20,832		0.0000	1.0000	10.22
85.5	20,832		0.0000	1.0000	10.22
86.5	20,832		0.0000	1.0000	10.22
87.5	19,756		0.0000	1.0000	10.22
88.5	19,756		0.0000	1.0000	10.22
89.5	5,751		0.0000	1.0000	10.22
90.5	5,751		0.0000	1.0000	10.22
91.5					10.22
92.5					
93.5	292		0.0000		
94.5	292	292	1.0000		
95.5					

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1909-2018 EXPERIENCE BAND 1975-1998, 2000-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	47,607,787		0.0000	1.0000	100.00
0.5	49,031,079		0.0000	1.0000	100.00
1.5	46,631,112	105,165	0.0023	0.9977	100.00
2.5	45,896,320	41,469	0.0009	0.9991	99.77
3.5	43,977,512	227,902	0.0052	0.9948	99.68
4.5	42,256,220	864,048	0.0204	0.9796	99.17
5.5	39,248,526	242,732	0.0062	0.9938	97.14
6.5	35,912,044	26,468	0.0007	0.9993	96.54
7.5	37,952,996	102,928	0.0027	0.9973	96.47
8.5	28,544,610	126,298	0.0044	0.9956	96.21
9.5	30,575,999	149,593	0.0049	0.9951	95.78
10.5	29,003,026	260,618	0.0090	0.9910	95.31
11.5	27,640,287	133,377	0.0048	0.9952	94.46
12.5	32,181,738	653,831	0.0203	0.9797	94.00
13.5	33,378,666	493,230	0.0148	0.9852	92.09
14.5	33,257,449	396,069	0.0119	0.9881	90.73
15.5	28,685,018	67,015	0.0023	0.9977	89.65
16.5	29,198,696	72,708	0.0025	0.9975	89.44
17.5	27,173,177	181,931	0.0067	0.9933	89.22
18.5	26,823,333	130,636	0.0049	0.9951	88.62
19.5	26,494,620	102,763	0.0039	0.9961	88.19
20.5	18,902,036	315,193	0.0167	0.9833	87.85
21.5	18,498,498	481,588	0.0260	0.9740	86.38
22.5	17,648,866	14,704	0.0008	0.9992	84.13
23.5	16,360,505	149,238	0.0091	0.9909	84.06
24.5	14,776,140	48,303	0.0033	0.9967	83.30
25.5	14,237,443	114,487	0.0080	0.9920	83.02
26.5	11,643,252	411,041	0.0353	0.9647	82.36
27.5	11,044,911	65,492	0.0059	0.9941	79.45
28.5	10,743,352	71,759	0.0067	0.9933	78.98
29.5	7,672,115	37,760	0.0049	0.9951	78.45
30.5	9,774,225	176,481	0.0181	0.9819	78.06
31.5	9,299,500	66,198	0.0071	0.9929	76.65
32.5	7,744,149	46,145	0.0060	0.9940	76.11
33.5	7,102,334	72,736	0.0102	0.9898	75.65
34.5	6,637,355	22,397	0.0034	0.9966	74.88
35.5	6,398,977	64,477	0.0101	0.9899	74.63
36.5	5,986,462	11,502	0.0019	0.9981	73.88
37.5	5,500,855	3,186	0.0006	0.9994	73.73
38.5	4,979,978	2,313	0.0005	0.9995	73.69

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2018			EXPERIENCE BAND 1975-1998, 2000-2018		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,966,433	28,301	0.0057	0.9943	73.66
40.5	4,403,661	347,590	0.0789	0.9211	73.24
41.5	5,078,698	1,219	0.0002	0.9998	67.46
42.5	5,239,730	13,794	0.0026	0.9974	67.44
43.5	5,225,688	178,843	0.0342	0.9658	67.26
44.5	3,941,109	1,866	0.0005	0.9995	64.96
45.5	3,901,276	15,297	0.0039	0.9961	64.93
46.5	3,950,671	3,483	0.0009	0.9991	64.67
47.5	3,956,575	271	0.0001	0.9999	64.62
48.5	3,949,878	4,053	0.0010	0.9990	64.61
49.5	1,012,090	941	0.0009	0.9991	64.55
50.5	1,009,951	11,801	0.0117	0.9883	64.49
51.5	1,016,306	857	0.0008	0.9992	63.73
52.5	986,934	22,365	0.0227	0.9773	63.68
53.5	986,612	719	0.0007	0.9993	62.24
54.5	960,890	12,869	0.0134	0.9866	62.19
55.5	3,262,315		0.0000	1.0000	61.36
56.5	3,127,402	293,501	0.0938	0.9062	61.36
57.5	2,775,284	2,518	0.0009	0.9991	55.60
58.5	2,767,808	14,643	0.0053	0.9947	55.55
59.5	2,735,017	10,268	0.0038	0.9962	55.26
60.5	2,216,860	115,678	0.0522	0.9478	55.05
61.5	2,100,024	414	0.0002	0.9998	52.18
62.5	2,088,614	101	0.0000	1.0000	52.17
63.5	305,418		0.0000	1.0000	52.16
64.5	304,037	3,350	0.0110	0.9890	52.16
65.5	304,550	215,824	0.7087	0.2913	51.59
66.5	87,682	3,889	0.0443	0.9557	15.03
67.5	81,318		0.0000	1.0000	14.36
68.5	76,277		0.0000	1.0000	14.36
69.5	46,415		0.0000	1.0000	14.36
70.5	60,505		0.0000	1.0000	14.36
71.5	36,106		0.0000	1.0000	14.36
72.5	36,257		0.0000	1.0000	14.36
73.5	36,235	160	0.0044	0.9956	14.36
74.5	36,075		0.0000	1.0000	14.30
75.5	36,075		0.0000	1.0000	14.30
76.5	36,075		0.0000	1.0000	14.30
77.5	35,085		0.0000	1.0000	14.30
78.5	35,085		0.0000	1.0000	14.30

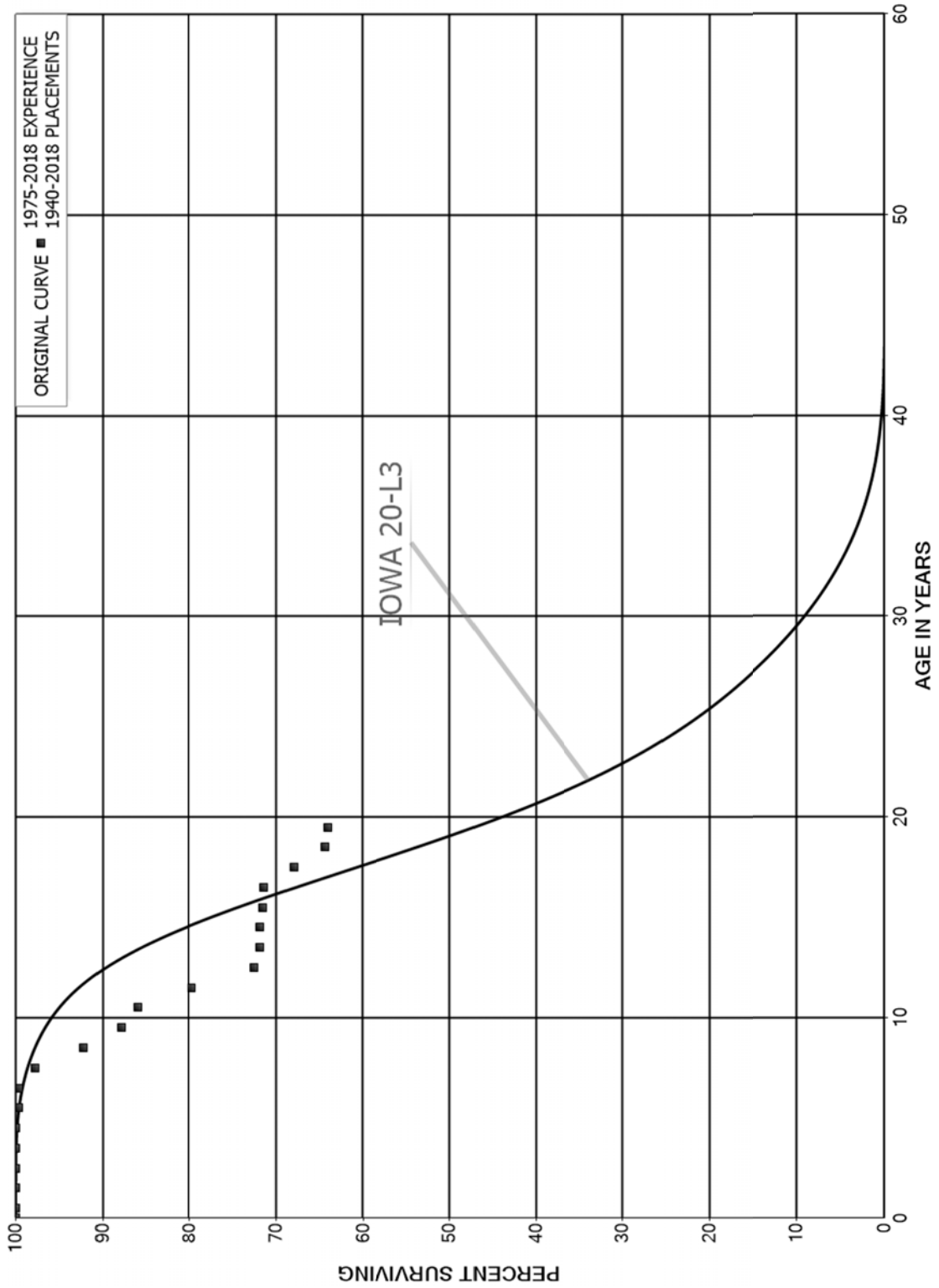
PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2018			EXPERIENCE BAND 1975-1998, 2000-2018		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	35,062		0.0000	1.0000	14.30
80.5	35,062		0.0000	1.0000	14.30
81.5	35,062	202	0.0058	0.9942	14.30
82.5	34,860		0.0000	1.0000	14.22
83.5	20,832		0.0000	1.0000	14.22
84.5	20,832		0.0000	1.0000	14.22
85.5	20,832		0.0000	1.0000	14.22
86.5	20,832		0.0000	1.0000	14.22
87.5	19,756		0.0000	1.0000	14.22
88.5	19,756		0.0000	1.0000	14.22
89.5	5,751		0.0000	1.0000	14.22
90.5	5,751		0.0000	1.0000	14.22
91.5					14.22
92.5					
93.5	292		0.0000		
94.5	292	292	1.0000		
95.5					

PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 397 COMMUNICATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 397 COMMUNICATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1940-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	138,516,724		0.0000	1.0000	100.00
0.5	128,141,952		0.0000	1.0000	100.00
1.5	125,690,534	32,447	0.0003	0.9997	100.00
2.5	115,500,597		0.0000	1.0000	99.97
3.5	109,386,124		0.0000	1.0000	99.97
4.5	86,800,469	267,101	0.0031	0.9969	99.97
5.5	80,000,193	8,570	0.0001	0.9999	99.67
6.5	75,941,464	1,484,466	0.0195	0.9805	99.66
7.5	40,683,541	2,299,748	0.0565	0.9435	97.71
8.5	15,494,080	733,556	0.0473	0.9527	92.18
9.5	14,181,201	299,499	0.0211	0.9789	87.82
10.5	5,448,563	396,601	0.0728	0.9272	85.97
11.5	4,174,468	379,737	0.0910	0.9090	79.71
12.5	3,604,074	30,215	0.0084	0.9916	72.46
13.5	3,629,220	3,290	0.0009	0.9991	71.85
14.5	3,654,487	12,361	0.0034	0.9966	71.78
15.5	3,329,845	5,971	0.0018	0.9982	71.54
16.5	2,170,722	106,464	0.0490	0.9510	71.41
17.5	2,073,159	106,659	0.0514	0.9486	67.91
18.5	1,984,001	11,342	0.0057	0.9943	64.42
19.5	1,975,926	614,917	0.3112	0.6888	64.05
20.5	1,334,031	9,497	0.0071	0.9929	44.12
21.5	1,324,534	475,177	0.3588	0.6412	43.80
22.5	849,357	13,302	0.0157	0.9843	28.09
23.5	836,228	663	0.0008	0.9992	27.65
24.5	838,349	46,425	0.0554	0.9446	27.63
25.5	791,924	9,146	0.0115	0.9885	26.10
26.5	782,777		0.0000	1.0000	25.80
27.5	782,777	16,988	0.0217	0.9783	25.80
28.5	765,789	192,730	0.2517	0.7483	25.24
29.5	573,059	4,830	0.0084	0.9916	18.88
30.5	573,661		0.0000	1.0000	18.73
31.5	573,661	95,295	0.1661	0.8339	18.73
32.5	478,366	52,705	0.1102	0.8898	15.61
33.5	425,661		0.0000	1.0000	13.89
34.5	426,297		0.0000	1.0000	13.89
35.5	426,297	18,913	0.0444	0.9556	13.89
36.5	407,384		0.0000	1.0000	13.28
37.5	407,384		0.0000	1.0000	13.28
38.5	407,384	1,560	0.0038	0.9962	13.28

PECO ENERGY COMPANY
ELECTRIC PLANT

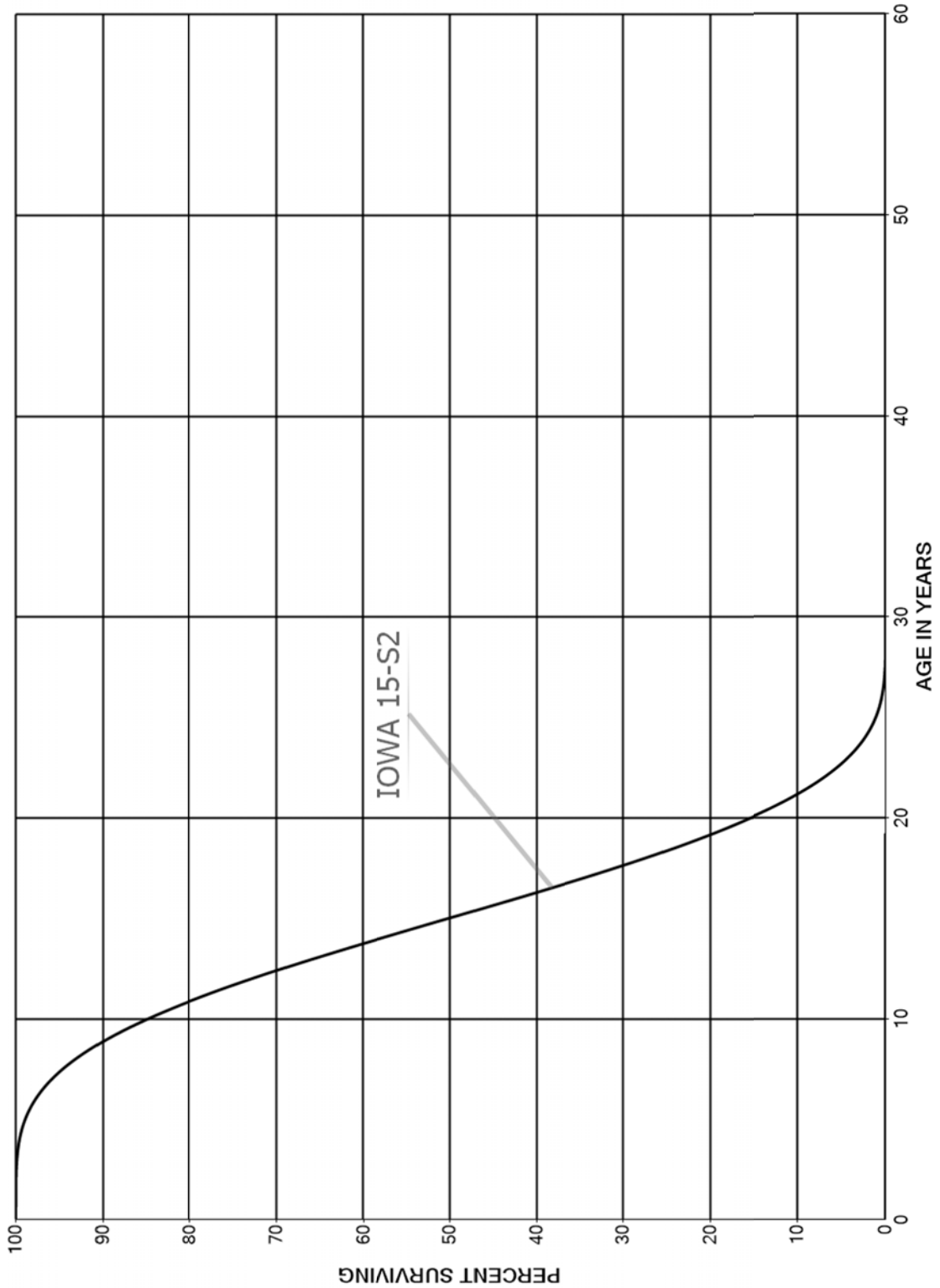
ACCOUNT 397 COMMUNICATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-2018 EXPERIENCE BAND 1975-2018

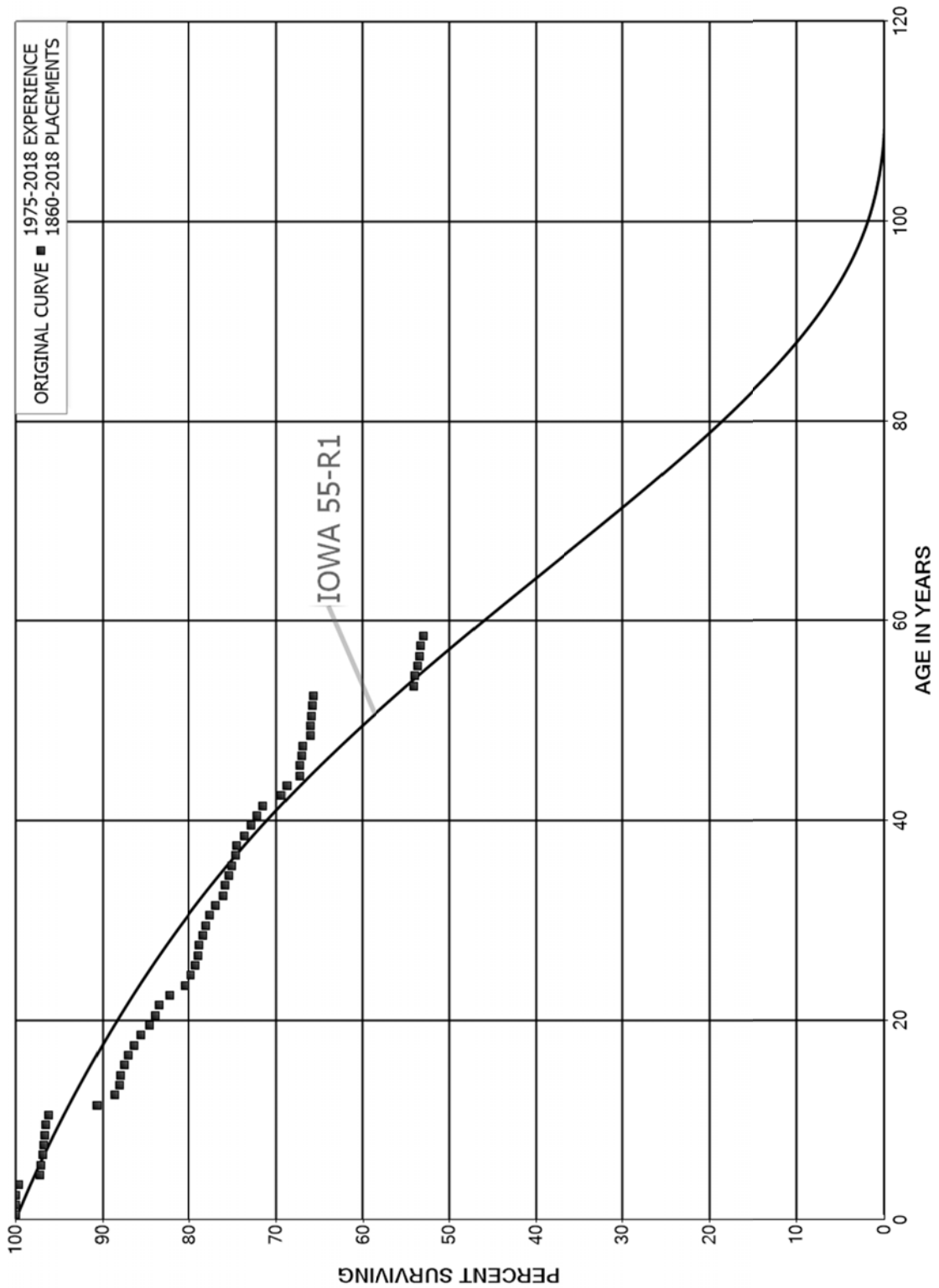
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	405,824	20,375	0.0502	0.9498	13.23
40.5	385,448	15,574	0.0404	0.9596	12.56
41.5	369,875	22,393	0.0605	0.9395	12.06
42.5	347,481	20,043	0.0577	0.9423	11.33
43.5	327,438	24,175	0.0738	0.9262	10.67
44.5	303,264	28,660	0.0945	0.9055	9.88
45.5	274,604	28,756	0.1047	0.8953	8.95
46.5	245,848	1,397	0.0057	0.9943	8.01
47.5	244,451	24,025	0.0983	0.9017	7.97
48.5	220,427	43,642	0.1980	0.8020	7.18
49.5	176,785	27,233	0.1540	0.8460	5.76
50.5	149,552	49,558	0.3314	0.6686	4.87
51.5	99,994	3,138	0.0314	0.9686	3.26
52.5	96,856	46,687	0.4820	0.5180	3.16
53.5	50,168	9,432	0.1880	0.8120	1.64
54.5	40,736	14,382	0.3531	0.6469	1.33
55.5	26,354	6,398	0.2428	0.7572	0.86
56.5	19,956	6,734	0.3374	0.6626	0.65
57.5	13,222	4,197	0.3174	0.6826	0.43
58.5	9,025		0.0000	1.0000	0.29
59.5	9,025	173	0.0191	0.9809	0.29
60.5	8,852		0.0000	1.0000	0.29
61.5	8,852		0.0000	1.0000	0.29
62.5	8,852		0.0000	1.0000	0.29
63.5	8,852	2,784	0.3145	0.6855	0.29
64.5	6,068		0.0000	1.0000	0.20
65.5	6,068		0.0000	1.0000	0.20
66.5	6,068		0.0000	1.0000	0.20
67.5	6,068		0.0000	1.0000	0.20
68.5	6,068		0.0000	1.0000	0.20
69.5	6,068	5,432	0.8952	0.1048	0.20
70.5	636		0.0000	1.0000	0.02
71.5	636		0.0000	1.0000	0.02
72.5	636		0.0000	1.0000	0.02
73.5	636	636	1.0000		0.02
74.5					

PECO ENERGY COMPANY
ELECTRIC PLANT
ACCOUNT 397.1 COMMUNICATION EQUIPMENT - SMART METERS
SMOOTH SURVIVOR CURVE



COMMON PLANT

PECO ENERGY COMPANY
COMMON PLANT
ACCOUNT 390 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1860-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	292,853,441	20,000	0.0001	0.9999	100.00
0.5	285,873,379	145,482	0.0005	0.9995	99.99
1.5	273,480,741	105,866	0.0004	0.9996	99.94
2.5	301,063,823	859,482	0.0029	0.9971	99.90
3.5	296,622,024	7,209,641	0.0243	0.9757	99.62
4.5	289,511,319	260,414	0.0009	0.9991	97.20
5.5	282,811,290	958,706	0.0034	0.9966	97.11
6.5	281,223,194	241,851	0.0009	0.9991	96.78
7.5	276,769,471	235,933	0.0009	0.9991	96.70
8.5	251,545,442	244,508	0.0010	0.9990	96.61
9.5	236,895,000	727,661	0.0031	0.9969	96.52
10.5	229,662,228	13,455,307	0.0586	0.9414	96.22
11.5	211,448,185	4,595,056	0.0217	0.9783	90.59
12.5	201,582,600	1,201,238	0.0060	0.9940	88.62
13.5	199,620,656	391,150	0.0020	0.9980	88.09
14.5	196,578,538	877,725	0.0045	0.9955	87.92
15.5	173,363,839	942,955	0.0054	0.9946	87.53
16.5	169,500,443	1,184,423	0.0070	0.9930	87.05
17.5	167,130,081	1,651,892	0.0099	0.9901	86.44
18.5	166,476,907	1,956,623	0.0118	0.9882	85.59
19.5	164,918,666	1,330,631	0.0081	0.9919	84.58
20.5	119,273,329	498,251	0.0042	0.9958	83.90
21.5	112,921,372	1,687,624	0.0149	0.9851	83.55
22.5	109,669,541	2,396,285	0.0219	0.9781	82.30
23.5	83,608,953	741,223	0.0089	0.9911	80.50
24.5	79,723,434	550,453	0.0069	0.9931	79.79
25.5	71,632,184	229,199	0.0032	0.9968	79.24
26.5	66,990,261	138,609	0.0021	0.9979	78.98
27.5	64,244,880	354,190	0.0055	0.9945	78.82
28.5	62,032,038	273,112	0.0044	0.9956	78.38
29.5	61,336,288	325,800	0.0053	0.9947	78.04
30.5	59,990,347	499,533	0.0083	0.9917	77.62
31.5	57,628,789	645,789	0.0112	0.9888	76.98
32.5	55,789,886	167,928	0.0030	0.9970	76.12
33.5	55,036,871	338,281	0.0061	0.9939	75.89
34.5	52,933,832	221,682	0.0042	0.9958	75.42
35.5	51,531,510	372,088	0.0072	0.9928	75.10
36.5	50,843,099	51,156	0.0010	0.9990	74.56
37.5	49,778,300	607,222	0.0122	0.9878	74.49
38.5	48,769,958	488,982	0.0100	0.9900	73.58

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1860-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	48,293,778	409,028	0.0085	0.9915	72.84
40.5	47,492,955	444,730	0.0094	0.9906	72.22
41.5	46,322,318	1,394,186	0.0301	0.9699	71.55
42.5	44,821,885	414,145	0.0092	0.9908	69.39
43.5	44,365,968	913,296	0.0206	0.9794	68.75
44.5	43,381,314	44,154	0.0010	0.9990	67.34
45.5	43,066,880	136,973	0.0032	0.9968	67.27
46.5	16,761,748	26,728	0.0016	0.9984	67.06
47.5	16,771,601	220,864	0.0132	0.9868	66.95
48.5	12,158,262	9,511	0.0008	0.9992	66.07
49.5	12,145,058	6,898	0.0006	0.9994	66.02
50.5	8,969,462	17,665	0.0020	0.9980	65.98
51.5	8,413,523	18,884	0.0022	0.9978	65.85
52.5	8,391,474	1,489,638	0.1775	0.8225	65.70
53.5	6,706,322	11,752	0.0018	0.9982	54.04
54.5	6,683,361	37,224	0.0056	0.9944	53.94
55.5	4,203,252	23,497	0.0056	0.9944	53.64
56.5	4,167,732	2,475	0.0006	0.9994	53.34
57.5	3,361,704	21,365	0.0064	0.9936	53.31
58.5	3,288,513	28,657	0.0087	0.9913	52.97
59.5	2,742,420	13,170	0.0048	0.9952	52.51
60.5	2,616,214	5,565	0.0021	0.9979	52.26
61.5	2,563,769	8,735	0.0034	0.9966	52.15
62.5	1,159,487	3,288	0.0028	0.9972	51.97
63.5	1,143,644	20,784	0.0182	0.9818	51.82
64.5	1,121,118	11,694	0.0104	0.9896	50.88
65.5	1,030,175	1,332	0.0013	0.9987	50.35
66.5	956,605	1,355	0.0014	0.9986	50.28
67.5	930,562		0.0000	1.0000	50.21
68.5	927,425	2,039	0.0022	0.9978	50.21
69.5	865,647	96,338	0.1113	0.8887	50.10
70.5	769,070	2,952	0.0038	0.9962	44.53
71.5	765,524		0.0000	1.0000	44.36
72.5	764,406	6,638	0.0087	0.9913	44.36
73.5	757,768	316	0.0004	0.9996	43.97
74.5	305,172	9,660	0.0317	0.9683	43.95
75.5	295,513	4,965	0.0168	0.9832	42.56
76.5	286,572	18,852	0.0658	0.9342	41.85
77.5	266,504	8,602	0.0323	0.9677	39.09
78.5	248,396	108	0.0004	0.9996	37.83

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1860-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	248,311	8,300	0.0334	0.9666	37.81
80.5	231,701	1,542	0.0067	0.9933	36.55
81.5	179,528	19,278	0.1074	0.8926	36.31
82.5	161,069		0.0000	1.0000	32.41
83.5	169,631		0.0000	1.0000	32.41
84.5	169,631	201	0.0012	0.9988	32.41
85.5	169,405		0.0000	1.0000	32.37
86.5	169,405	2,543	0.0150	0.9850	32.37
87.5	166,458		0.0000	1.0000	31.88
88.5	166,336	3,206	0.0193	0.9807	31.88
89.5	163,131	111,106	0.6811	0.3189	31.27
90.5	52,024		0.0000	1.0000	9.97
91.5	38,046	222	0.0058	0.9942	9.97
92.5	37,824		0.0000	1.0000	9.91
93.5	31,885	22,859	0.7169	0.2831	9.91
94.5	3,118		0.0000	1.0000	2.81
95.5	3,118		0.0000	1.0000	2.81
96.5	2,885		0.0000	1.0000	2.81
97.5	2,885		0.0000	1.0000	2.81
98.5	2,885		0.0000	1.0000	2.81
99.5	2,885		0.0000	1.0000	2.81
100.5	2,885		0.0000	1.0000	2.81
101.5	2,885	151	0.0523	0.9477	2.81
102.5	2,734		0.0000	1.0000	2.66
103.5	2,734		0.0000	1.0000	2.66
104.5	819		0.0000	1.0000	2.66
105.5	819		0.0000	1.0000	2.66
106.5	819		0.0000	1.0000	2.66
107.5	819		0.0000	1.0000	2.66
108.5	819		0.0000	1.0000	2.66
109.5	819		0.0000	1.0000	2.66
110.5	819		0.0000	1.0000	2.66
111.5	819		0.0000	1.0000	2.66
112.5	819		0.0000	1.0000	2.66
113.5	819		0.0000	1.0000	2.66
114.5	1,359		0.0000	1.0000	2.66
115.5	1,359		0.0000	1.0000	2.66
116.5	1,359		0.0000	1.0000	2.66
117.5	1,359		0.0000	1.0000	2.66
118.5	1,359	540	0.3973	0.6027	2.66

PECO ENERGY COMPANY
COMMON PLANT

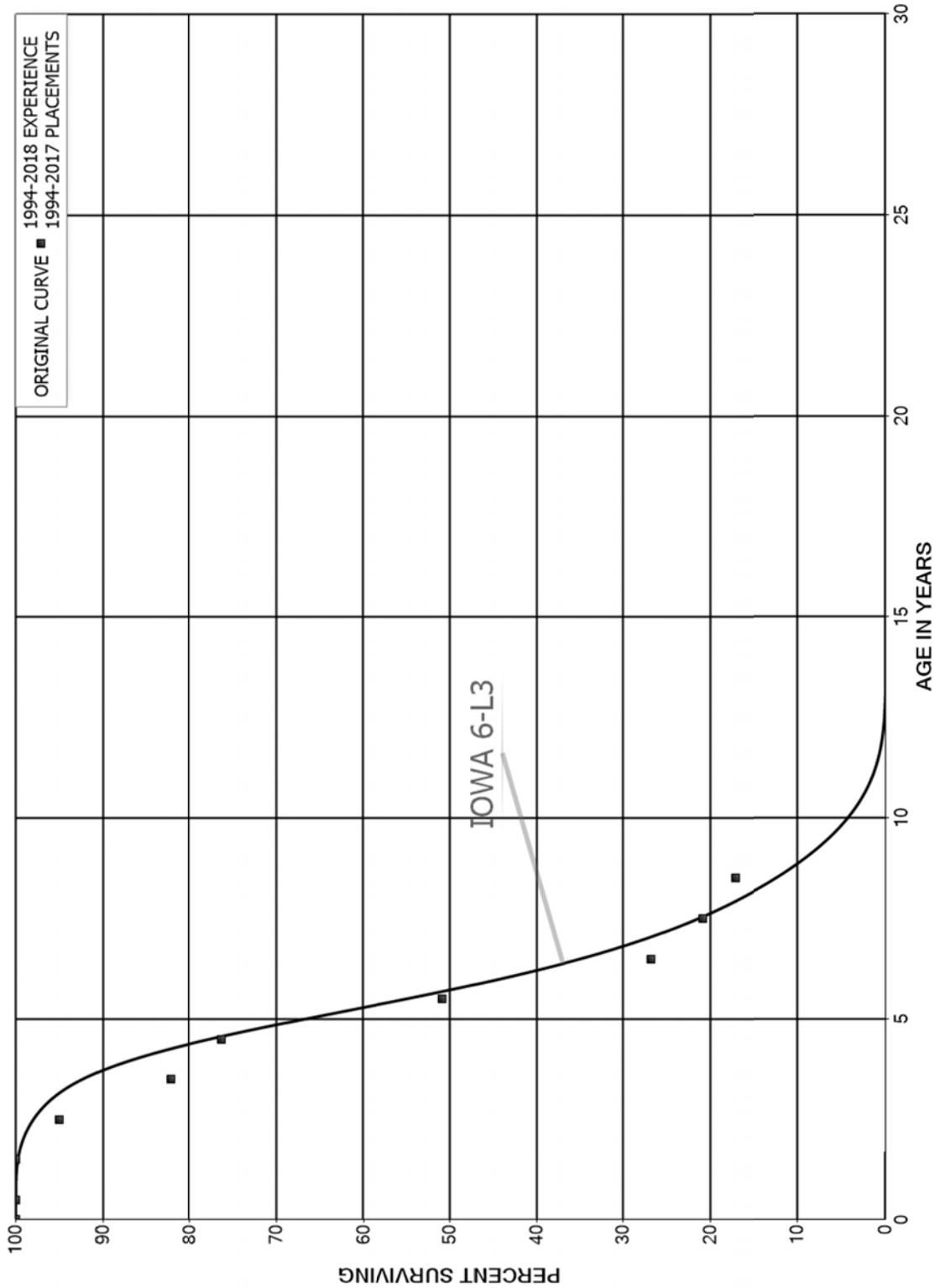
ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1860-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	819		0.0000	1.0000	1.60
120.5	819	156	0.1904	0.8096	1.60
121.5	663		0.0000	1.0000	1.30
122.5	663		0.0000	1.0000	1.30
123.5	663		0.0000	1.0000	1.30
124.5	663		0.0000	1.0000	1.30
125.5	663		0.0000	1.0000	1.30
126.5					1.30

PECO ENERGY COMPANY
COMMON PLANT
ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - AUTOMOBILES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
COMMON PLANT

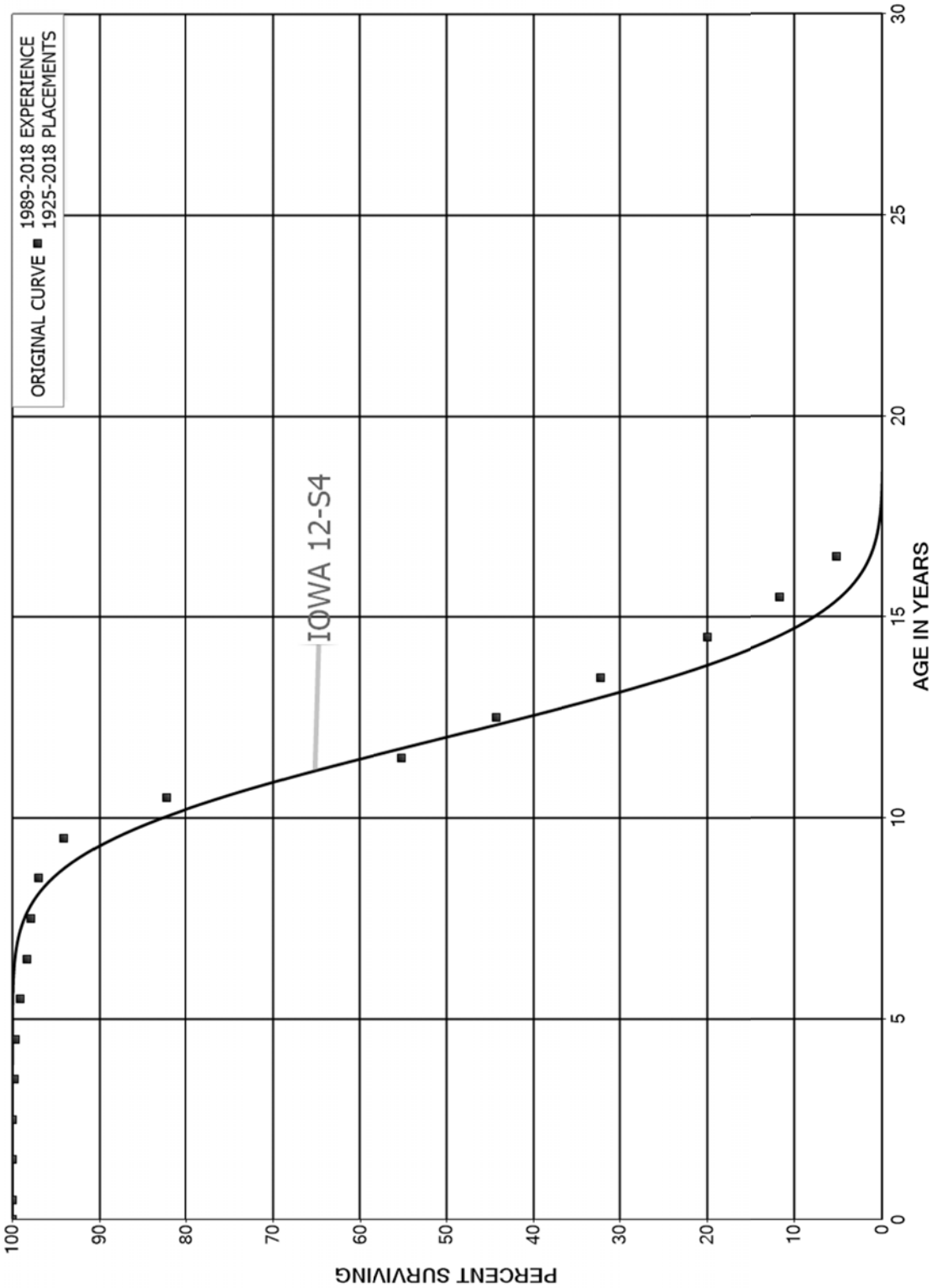
ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - AUTOMOBILES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1994-2017 EXPERIENCE BAND 1994-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	626,684		0.0000	1.0000	100.00
0.5	626,684		0.0000	1.0000	100.00
1.5	624,378	31,533	0.0505	0.9495	100.00
2.5	592,845	79,818	0.1346	0.8654	94.95
3.5	512,275	36,949	0.0721	0.9279	82.17
4.5	475,326	158,583	0.3336	0.6664	76.24
5.5	316,743	150,072	0.4738	0.5262	50.80
6.5	166,671	36,785	0.2207	0.7793	26.73
7.5	129,886	23,593	0.1816	0.8184	20.83
8.5	106,293		0.0000	1.0000	17.05
9.5	106,293	15,711	0.1478	0.8522	17.05
10.5	90,582		0.0000	1.0000	14.53
11.5	90,582		0.0000	1.0000	14.53
12.5	90,582		0.0000	1.0000	14.53
13.5	90,582		0.0000	1.0000	14.53
14.5	90,582		0.0000	1.0000	14.53
15.5	90,582		0.0000	1.0000	14.53
16.5					14.53

PECO ENERGY COMPANY
COMMON PLANT
ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - LIGHT TRUCKS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - LIGHT TRUCKS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1925-2018 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	49,586,779		0.0000	1.0000	100.00
0.5	46,845,477		0.0000	1.0000	100.00
1.5	44,004,759	11,997	0.0003	0.9997	100.00
2.5	38,906,566	105,422	0.0027	0.9973	99.97
3.5	37,314,216	36,949	0.0010	0.9990	99.70
4.5	32,949,084	159,908	0.0049	0.9951	99.60
5.5	29,593,456	258,196	0.0087	0.9913	99.12
6.5	28,541,829	111,576	0.0039	0.9961	98.25
7.5	27,160,269	244,783	0.0090	0.9910	97.87
8.5	22,827,473	683,232	0.0299	0.9701	96.99
9.5	21,482,209	2,682,687	0.1249	0.8751	94.09
10.5	18,002,322	5,935,440	0.3297	0.6703	82.34
11.5	11,467,149	2,266,049	0.1976	0.8024	55.19
12.5	8,793,544	2,396,461	0.2725	0.7275	44.28
13.5	6,268,890	2,382,360	0.3800	0.6200	32.22
14.5	3,928,528	1,644,933	0.4187	0.5813	19.97
15.5	2,233,736	1,232,525	0.5518	0.4482	11.61
16.5	259,329	90,943	0.3507	0.6493	5.20
17.5	172,822	33,567	0.1942	0.8058	3.38
18.5	162,664	51,133	0.3143	0.6857	2.72
19.5	138,830	19,213	0.1384	0.8616	1.87
20.5	138,917	22,499	0.1620	0.8380	1.61
21.5	122,569	13,368	0.1091	0.8909	1.35
22.5	109,200	1,932	0.0177	0.9823	1.20
23.5	110,421	7,593	0.0688	0.9312	1.18
24.5	103,475	62,733	0.6063	0.3937	1.10
25.5	49,964	2,348	0.0470	0.9530	0.43
26.5	48,820	9,941	0.2036	0.7964	0.41
27.5	42,894	2,939	0.0685	0.9315	0.33
28.5	41,531	12,257	0.2951	0.7049	0.31
29.5	34,074	7,519	0.2207	0.7793	0.22
30.5	27,660	9,601	0.3471	0.6529	0.17
31.5	19,361	2,226	0.1150	0.8850	0.11
32.5	17,440	5,929	0.3400	0.6600	0.10
33.5	22,354	720	0.0322	0.9678	0.06
34.5	22,434	10,194	0.4544	0.5456	0.06
35.5	12,240	6,040	0.4934	0.5066	0.03
36.5	6,200	462	0.0746	0.9254	0.02
37.5	5,738	1,834	0.3196	0.6804	0.02
38.5	4,211	116	0.0276	0.9724	0.01

PECO ENERGY COMPANY
COMMON PLANT

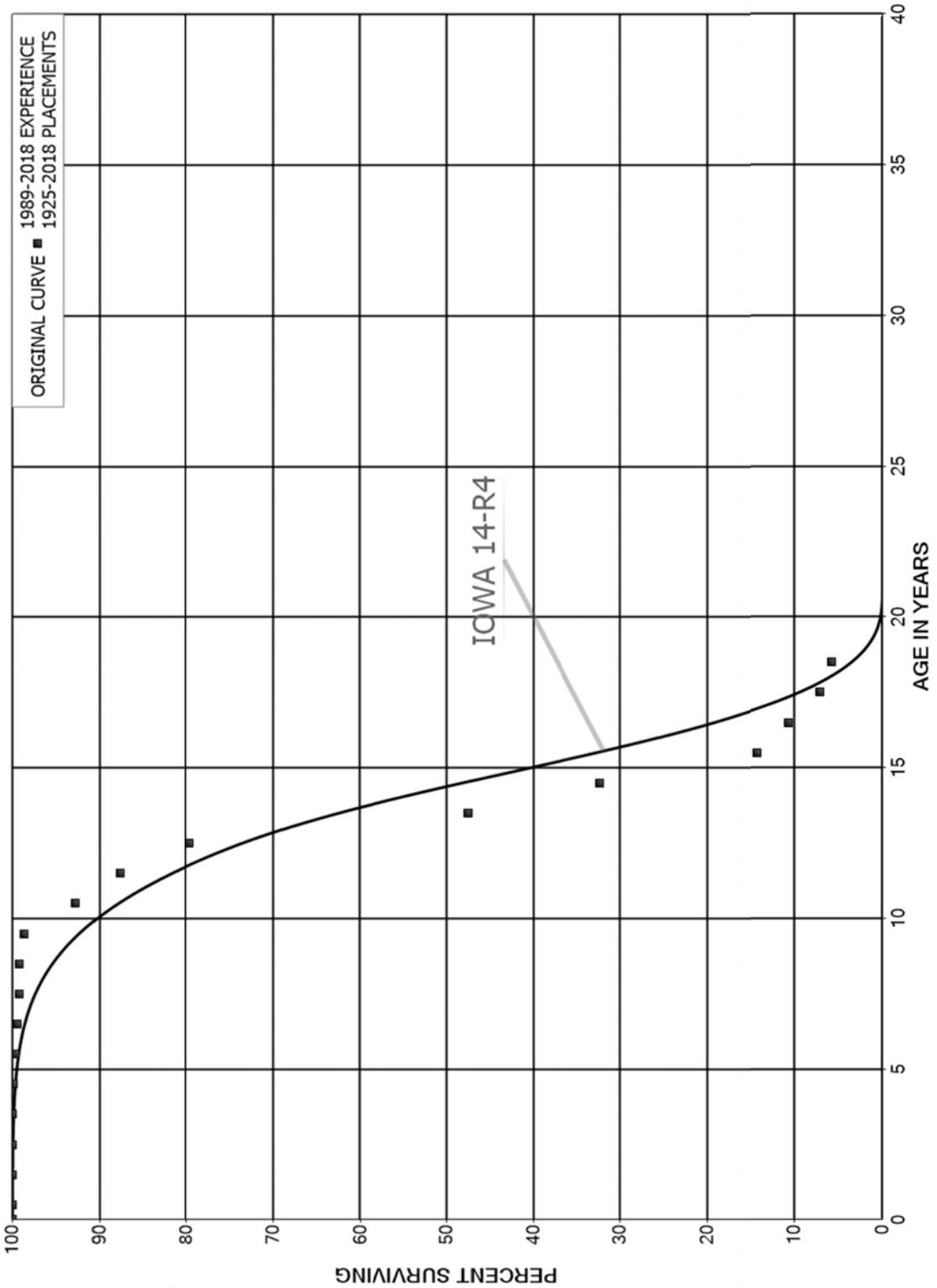
ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - LIGHT TRUCKS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1925-2018 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,468	307	0.0688	0.9312	0.01
40.5	5,441	1,105	0.2032	0.7968	0.01
41.5	4,335	415	0.0957	0.9043	0.01
42.5	3,955	221	0.0560	0.9440	0.01
43.5	3,733	1,744	0.4671	0.5329	0.01
44.5	1,989	354	0.1780	0.8220	0.00
45.5	1,635		0.0000	1.0000	0.00
46.5	1,635		0.0000	1.0000	0.00
47.5	1,793	158	0.0879	0.9121	0.00
48.5	1,635		0.0000	1.0000	0.00
49.5	1,635	321	0.1964	0.8036	0.00
50.5	1,314	1,280	0.9741	0.0259	0.00
51.5	34		0.0000	1.0000	0.00
52.5	34	34	1.0000		0.00
53.5					
54.5					
55.5					
56.5					
57.5					
58.5					
59.5	781	432	0.5531		
60.5	349	349	1.0000		
61.5					
62.5	92		0.0000		
63.5	225	92	0.4068		
64.5	133	133	1.0000		
65.5					

PECO ENERGY COMPANY
COMMON PLANT
ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1925-2018 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	114,477,278		0.0000	1.0000	100.00
0.5	109,693,137		0.0000	1.0000	100.00
1.5	102,709,459	11,997	0.0001	0.9999	100.00
2.5	95,649,976	79,818	0.0008	0.9992	99.99
3.5	92,414,445	106,819	0.0012	0.9988	99.90
4.5	81,887,805	159,908	0.0020	0.9980	99.79
5.5	74,235,888	172,821	0.0023	0.9977	99.59
6.5	69,366,233	103,910	0.0015	0.9985	99.36
7.5	65,217,945	14,382	0.0002	0.9998	99.21
8.5	57,310,841	312,849	0.0055	0.9945	99.19
9.5	53,840,816	3,204,465	0.0595	0.9405	98.65
10.5	42,346,858	2,361,344	0.0558	0.9442	92.78
11.5	35,716,475	3,249,703	0.0910	0.9090	87.61
12.5	30,394,321	12,246,918	0.4029	0.5971	79.63
13.5	18,085,941	5,799,113	0.3206	0.6794	47.55
14.5	11,456,046	6,424,106	0.5608	0.4392	32.30
15.5	5,071,946	1,281,529	0.2527	0.7473	14.19
16.5	3,806,176	1,253,951	0.3295	0.6705	10.60
17.5	2,554,487	500,303	0.1959	0.8041	7.11
18.5	2,077,594	223,197	0.1074	0.8926	5.72
19.5	1,881,695	362,005	0.1924	0.8076	5.10
20.5	1,538,991	258,520	0.1680	0.8320	4.12
21.5	1,083,970	66,236	0.0611	0.9389	3.43
22.5	887,467	168,402	0.1898	0.8102	3.22
23.5	722,218	7,593	0.0105	0.9895	2.61
24.5	715,272	527,780	0.7379	0.2621	2.58
25.5	196,713	34,882	0.1773	0.8227	0.68
26.5	163,035	105,908	0.6496	0.3504	0.56
27.5	61,142	21,186	0.3465	0.6535	0.20
28.5	41,531	12,257	0.2951	0.7049	0.13
29.5	34,074	7,519	0.2207	0.7793	0.09
30.5	27,660	9,601	0.3471	0.6529	0.07
31.5	19,361	2,226	0.1150	0.8850	0.05
32.5	17,440	5,929	0.3400	0.6600	0.04
33.5	157,152	720	0.0046	0.9954	0.03
34.5	157,231	10,194	0.0648	0.9352	0.03
35.5	147,037	6,040	0.0411	0.9589	0.02
36.5	140,997	462	0.0033	0.9967	0.02
37.5	140,535	1,834	0.0131	0.9869	0.02
38.5	139,008	116	0.0008	0.9992	0.02

PECO ENERGY COMPANY
COMMON PLANT

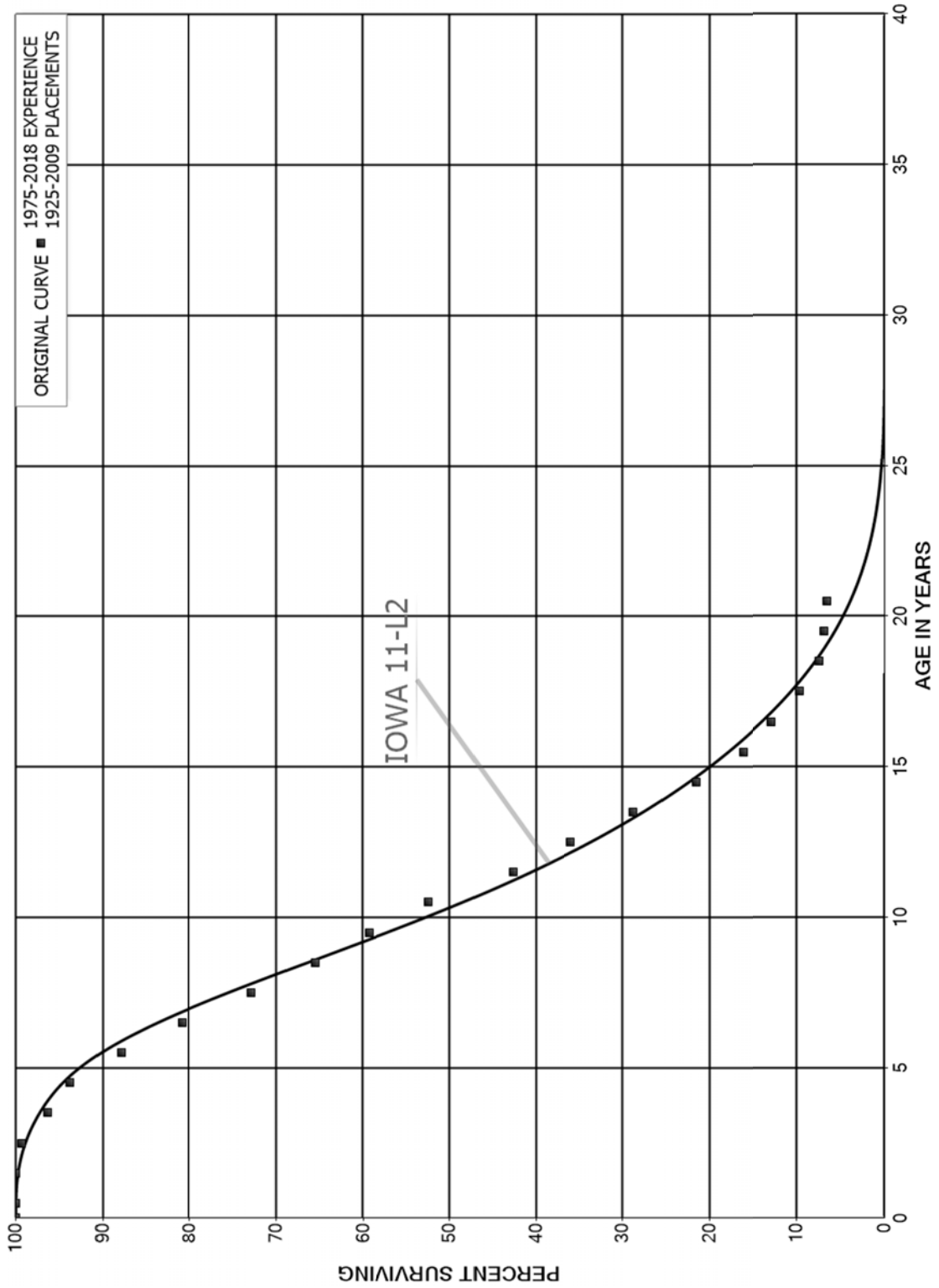
ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1925-2018 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	139,265	307	0.0022	0.9978	0.02
40.5	140,238	1,105	0.0079	0.9921	0.02
41.5	139,133	415	0.0030	0.9970	0.02
42.5	138,752	221	0.0016	0.9984	0.02
43.5	138,530	1,744	0.0126	0.9874	0.02
44.5	136,787	354	0.0026	0.9974	0.02
45.5	136,432		0.0000	1.0000	0.02
46.5	136,432		0.0000	1.0000	0.02
47.5	136,590	158	0.0012	0.9988	0.02
48.5	136,432		0.0000	1.0000	0.02
49.5	136,432	321	0.0024	0.9976	0.02
50.5	136,111	1,280	0.0094	0.9906	0.02
51.5	134,831		0.0000	1.0000	0.02
52.5	134,831	34	0.0003	0.9997	0.02
53.5	134,797		0.0000	1.0000	0.02
54.5	134,797		0.0000	1.0000	0.02
55.5	134,797		0.0000	1.0000	0.02
56.5	134,797		0.0000	1.0000	0.02
57.5	134,797		0.0000	1.0000	0.02
58.5	134,797		0.0000	1.0000	0.02
59.5	135,578	432	0.0032	0.9968	0.02
60.5	135,146	349	0.0026	0.9974	0.02
61.5	134,797	134,797	1.0000		0.02
62.5	92		0.0000	1.0000	
63.5	225	92	0.4068		
64.5	133	133	1.0000		
65.5					

PECO ENERGY COMPANY
COMMON PLANT
ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - TRACTORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - TRACTORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1925-2009 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,815,986		0.0000	1.0000	100.00
0.5	2,227,395	200	0.0001	0.9999	100.00
1.5	2,751,680	18,422	0.0067	0.9933	99.99
2.5	3,095,942	93,883	0.0303	0.9697	99.32
3.5	3,564,308	95,644	0.0268	0.9732	96.31
4.5	3,777,378	236,971	0.0627	0.9373	93.73
5.5	4,161,230	331,845	0.0797	0.9203	87.85
6.5	4,129,334	411,701	0.0997	0.9003	80.84
7.5	3,838,137	384,385	0.1001	0.8999	72.78
8.5	3,506,812	332,635	0.0949	0.9051	65.49
9.5	3,235,545	377,878	0.1168	0.8832	59.28
10.5	2,994,241	555,417	0.1855	0.8145	52.36
11.5	2,657,314	418,195	0.1574	0.8426	42.64
12.5	2,329,055	469,541	0.2016	0.7984	35.93
13.5	1,928,268	484,356	0.2512	0.7488	28.69
14.5	1,478,924	376,259	0.2544	0.7456	21.48
15.5	1,129,619	226,215	0.2003	0.7997	16.02
16.5	861,913	214,899	0.2493	0.7507	12.81
17.5	649,982	153,683	0.2364	0.7636	9.62
18.5	499,330	37,052	0.0742	0.9258	7.34
19.5	473,121	20,477	0.0433	0.9567	6.80
20.5	456,986	23,748	0.0520	0.9480	6.50
21.5	433,451	89,496	0.2065	0.7935	6.17
22.5	344,443	4,971	0.0144	0.9856	4.89
23.5	163,248	8,684	0.0532	0.9468	4.82
24.5	154,888	66,118	0.4269	0.5731	4.57
25.5	90,110	4,218	0.0468	0.9532	2.62
26.5	87,210	13,317	0.1527	0.8473	2.49
27.5	74,166	3,626	0.0489	0.9511	2.11
28.5	70,862	13,658	0.1927	0.8073	2.01
29.5	57,204	9,338	0.1632	0.8368	1.62
30.5	47,866	11,141	0.2328	0.7672	1.36
31.5	36,724	2,359	0.0642	0.9358	1.04
32.5	34,365	7,767	0.2260	0.7740	0.97
33.5	26,913	1,781	0.0662	0.9338	0.75
34.5	25,133	10,194	0.4056	0.5944	0.70
35.5	15,003	6,089	0.4058	0.5942	0.42
36.5	8,915	462	0.0519	0.9481	0.25
37.5	8,653	2,174	0.2513	0.7487	0.24
38.5	6,479	181	0.0279	0.9721	0.18

PECO ENERGY COMPANY
COMMON PLANT

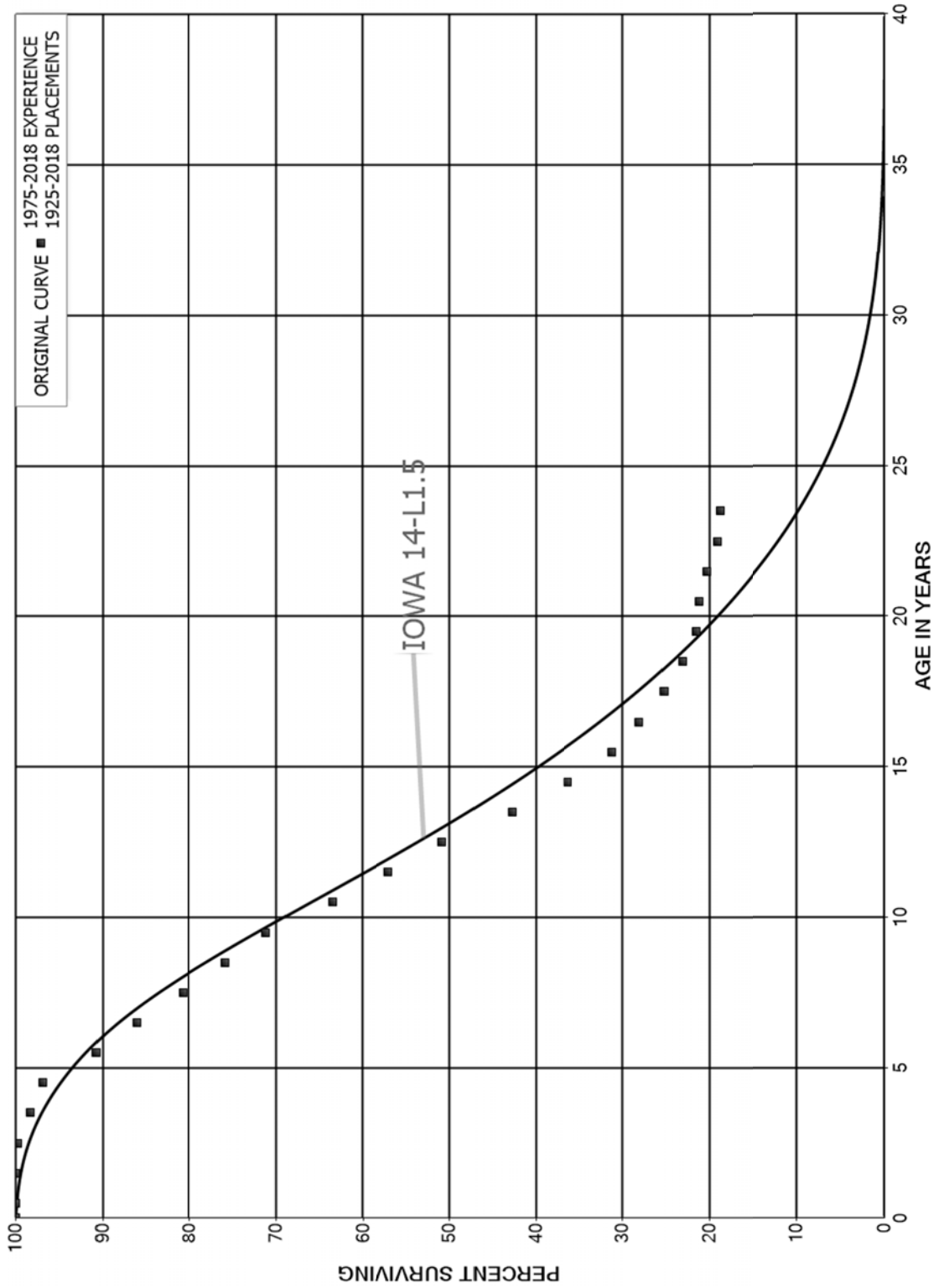
ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - TRACTORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1925-2009 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,298	508	0.0806	0.9194	0.17
40.5	5,790	1,105	0.1909	0.8091	0.16
41.5	4,685	415	0.0886	0.9114	0.13
42.5	4,270	379	0.0888	0.9112	0.12
43.5	3,891	1,744	0.4482	0.5518	0.11
44.5	2,147	354	0.1650	0.8350	0.06
45.5	2,573		0.0000	1.0000	0.05
46.5	2,573		0.0000	1.0000	0.05
47.5	2,573	158	0.0613	0.9387	0.05
48.5	2,507		0.0000	1.0000	0.05
49.5	2,641	321	0.1216	0.8784	0.05
50.5	2,320	1,280	0.5518	0.4482	0.04
51.5	1,040		0.0000	1.0000	0.02
52.5	1,040	34	0.0327	0.9673	0.02
53.5	1,006		0.0000	1.0000	0.02
54.5	1,006		0.0000	1.0000	0.02
55.5	1,006		0.0000	1.0000	0.02
56.5	1,006		0.0000	1.0000	0.02
57.5	1,006		0.0000	1.0000	0.02
58.5	1,006		0.0000	1.0000	0.02
59.5	1,006	432	0.4293	0.5707	0.02
60.5	574	349	0.6079	0.3921	0.01
61.5	225		0.0000	1.0000	0.00
62.5	225		0.0000	1.0000	0.00
63.5	225	92	0.4068	0.5932	0.00
64.5	133	133	1.0000		0.00
65.5					

PECO ENERGY COMPANY
COMMON PLANT
ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1925-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,956,153		0.0000	1.0000	100.00
0.5	6,983,706	200	0.0000	1.0000	100.00
1.5	6,995,480	18,411	0.0026	0.9974	100.00
2.5	6,517,340	93,827	0.0144	0.9856	99.73
3.5	6,583,888	98,087	0.0149	0.9851	98.30
4.5	6,518,825	411,278	0.0631	0.9369	96.83
5.5	6,692,114	344,481	0.0515	0.9485	90.72
6.5	6,652,707	411,454	0.0618	0.9382	86.05
7.5	6,339,747	384,154	0.0606	0.9394	80.73
8.5	5,726,699	349,340	0.0610	0.9390	75.84
9.5	5,489,389	596,655	0.1087	0.8913	71.21
10.5	5,029,225	506,829	0.1008	0.8992	63.47
11.5	4,372,833	476,565	0.1090	0.8910	57.08
12.5	3,909,939	628,709	0.1608	0.8392	50.86
13.5	3,330,658	502,703	0.1509	0.8491	42.68
14.5	2,866,614	402,809	0.1405	0.8595	36.24
15.5	2,467,694	243,659	0.0987	0.9013	31.15
16.5	2,052,646	214,770	0.1046	0.8954	28.07
17.5	1,825,289	153,591	0.0841	0.9159	25.13
18.5	1,608,474	105,980	0.0659	0.9341	23.02
19.5	1,513,331	26,808	0.0177	0.9823	21.50
20.5	1,490,862	56,296	0.0378	0.9622	21.12
21.5	1,195,540	73,330	0.0613	0.9387	20.32
22.5	912,976	16,333	0.0179	0.9821	19.08
23.5	764,879	8,679	0.0113	0.9887	18.74
24.5	630,876	66,078	0.1047	0.8953	18.52
25.5	566,136	4,215	0.0074	0.9926	16.58
26.5	563,239	13,309	0.0236	0.9764	16.46
27.5	550,202	24,903	0.0453	0.9547	16.07
28.5	525,621	13,650	0.0260	0.9740	15.34
29.5	511,971	9,332	0.0182	0.9818	14.94
30.5	483,994	15,335	0.0317	0.9683	14.67
31.5	468,659	4,258	0.0091	0.9909	14.21
32.5	464,402	70,463	0.1517	0.8483	14.08
33.5	394,254	1,780	0.0045	0.9955	11.94
34.5	392,475	10,188	0.0260	0.9740	11.89
35.5	382,351	6,085	0.0159	0.9841	11.58
36.5	376,266	23,362	0.0621	0.9379	11.40
37.5	353,105	51,673	0.1463	0.8537	10.69
38.5	301,432	181	0.0006	0.9994	9.12

PECO ENERGY COMPANY
COMMON PLANT

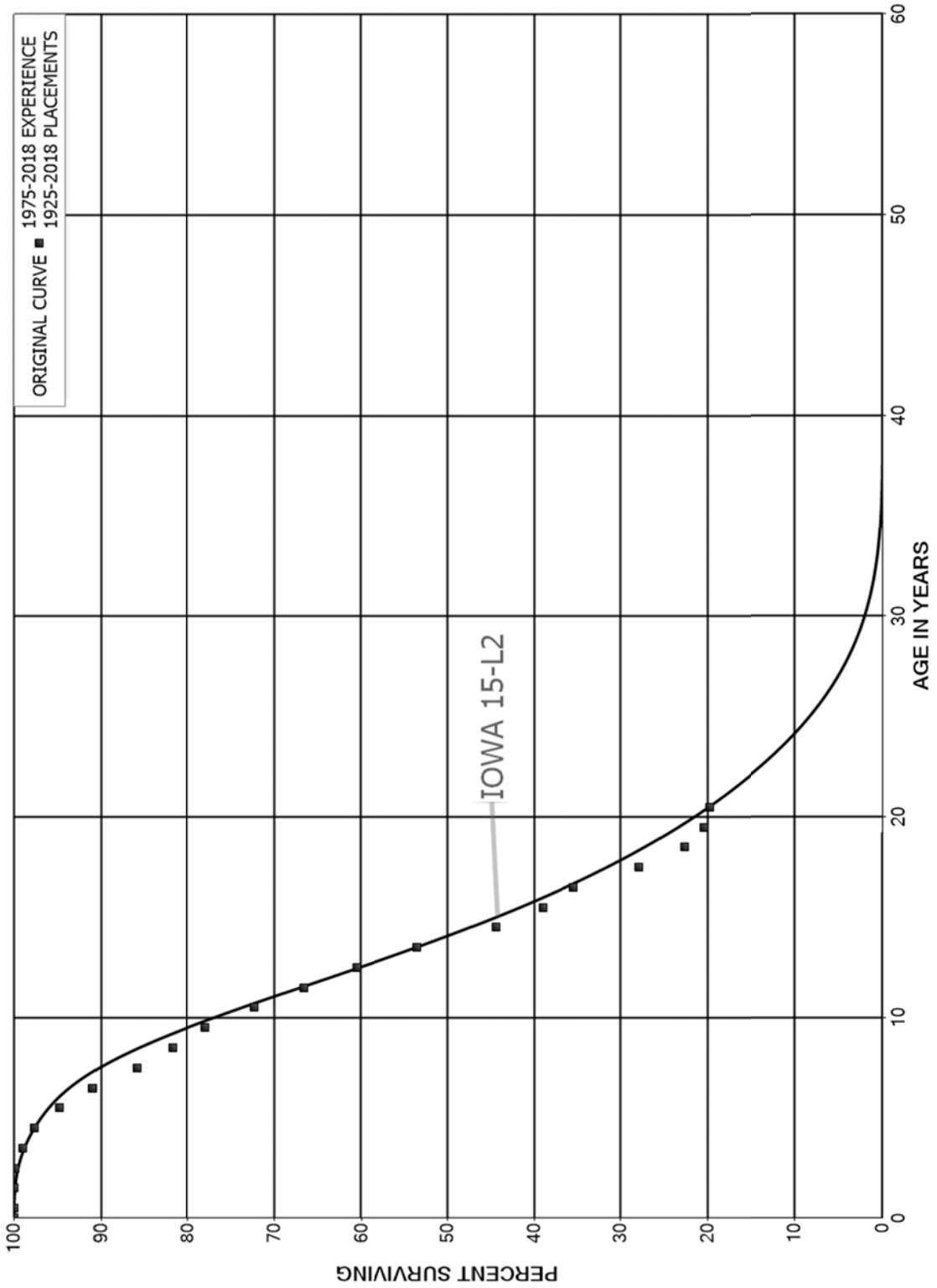
ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1925-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	301,251	23,507	0.0780	0.9220	9.12
40.5	253,736	1,105	0.0044	0.9956	8.41
41.5	252,632	415	0.0016	0.9984	8.37
42.5	250,673	379	0.0015	0.9985	8.36
43.5	224,942	1,743	0.0077	0.9923	8.34
44.5	222,385	1,154	0.0052	0.9948	8.28
45.5	154,302	800	0.0052	0.9948	8.24
46.5	148,977		0.0000	1.0000	8.19
47.5	142,333	158	0.0011	0.9989	8.19
48.5	114,535		0.0000	1.0000	8.18
49.5	103,323	1,121	0.0108	0.9892	8.18
50.5	47,591	1,279	0.0269	0.9731	8.10
51.5	22,913		0.0000	1.0000	7.88
52.5	19,760	34	0.0017	0.9983	7.88
53.5	19,726		0.0000	1.0000	7.86
54.5	19,726		0.0000	1.0000	7.86
55.5	18,699		0.0000	1.0000	7.86
56.5	17,727	6,574	0.3708	0.6292	7.86
57.5	7,614		0.0000	1.0000	4.95
58.5	1,940		0.0000	1.0000	4.95
59.5	1,940	1,261	0.6499	0.3501	4.95
60.5	679	455	0.6690	0.3310	1.73
61.5	225		0.0000	1.0000	0.57
62.5	225		0.0000	1.0000	0.57
63.5	225	91	0.4068	0.5932	0.57
64.5	133	133	1.0000		0.34
65.5					

PECO ENERGY COMPANY
COMMON PLANT
ACCOUNT 392.6 TRANSPORTATION EQUIPMENT - OTHER VEHICLES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.6 TRANSPORTATION EQUIPMENT - OTHER VEHICLES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1925-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	14,072,027		0.0000	1.0000	100.00
0.5	14,375,046	200	0.0000	1.0000	100.00
1.5	13,702,034	18,411	0.0013	0.9987	100.00
2.5	11,305,445	102,247	0.0090	0.9910	99.86
3.5	8,323,982	113,472	0.0136	0.9864	98.96
4.5	8,196,556	241,679	0.0295	0.9705	97.61
5.5	8,575,328	339,446	0.0396	0.9604	94.73
6.5	8,287,200	468,849	0.0566	0.9434	90.98
7.5	7,933,245	384,154	0.0484	0.9516	85.84
8.5	7,320,795	332,435	0.0454	0.9546	81.68
9.5	6,960,635	504,804	0.0725	0.9275	77.97
10.5	6,442,859	503,955	0.0782	0.9218	72.32
11.5	5,792,238	538,220	0.0929	0.9071	66.66
12.5	4,437,894	512,727	0.1155	0.8845	60.47
13.5	3,682,994	625,153	0.1697	0.8303	53.48
14.5	3,092,832	376,034	0.1216	0.8784	44.40
15.5	2,441,677	226,079	0.0926	0.9074	39.00
16.5	1,038,932	223,038	0.2147	0.7853	35.39
17.5	818,861	153,591	0.1876	0.8124	27.79
18.5	663,158	64,816	0.0977	0.9023	22.58
19.5	609,178	20,465	0.0336	0.9664	20.37
20.5	593,053	23,734	0.0400	0.9600	19.69
21.5	569,532	15,181	0.0267	0.9733	18.90
22.5	526,154	27,718	0.0527	0.9473	18.40
23.5	429,172	44,088	0.1027	0.8973	17.43
24.5	311,263	66,078	0.2123	0.7877	15.64
25.5	218,979	4,215	0.0193	0.9807	12.32
26.5	209,961	13,309	0.0634	0.9366	12.08
27.5	196,925	3,624	0.0184	0.9816	11.32
28.5	194,543	13,650	0.0702	0.9298	11.11
29.5	180,893	9,332	0.0516	0.9484	10.33
30.5	171,561	11,135	0.0649	0.9351	9.79
31.5	160,426	8,458	0.0527	0.9473	9.16
32.5	151,968	12,363	0.0814	0.9186	8.68
33.5	139,921	1,780	0.0127	0.9873	7.97
34.5	138,141	10,188	0.0737	0.9263	7.87
35.5	125,127	6,085	0.0486	0.9514	7.29
36.5	119,042	462	0.0039	0.9961	6.93
37.5	118,781	2,173	0.0183	0.9817	6.91
38.5	116,608	181	0.0016	0.9984	6.78

PECO ENERGY COMPANY
COMMON PLANT

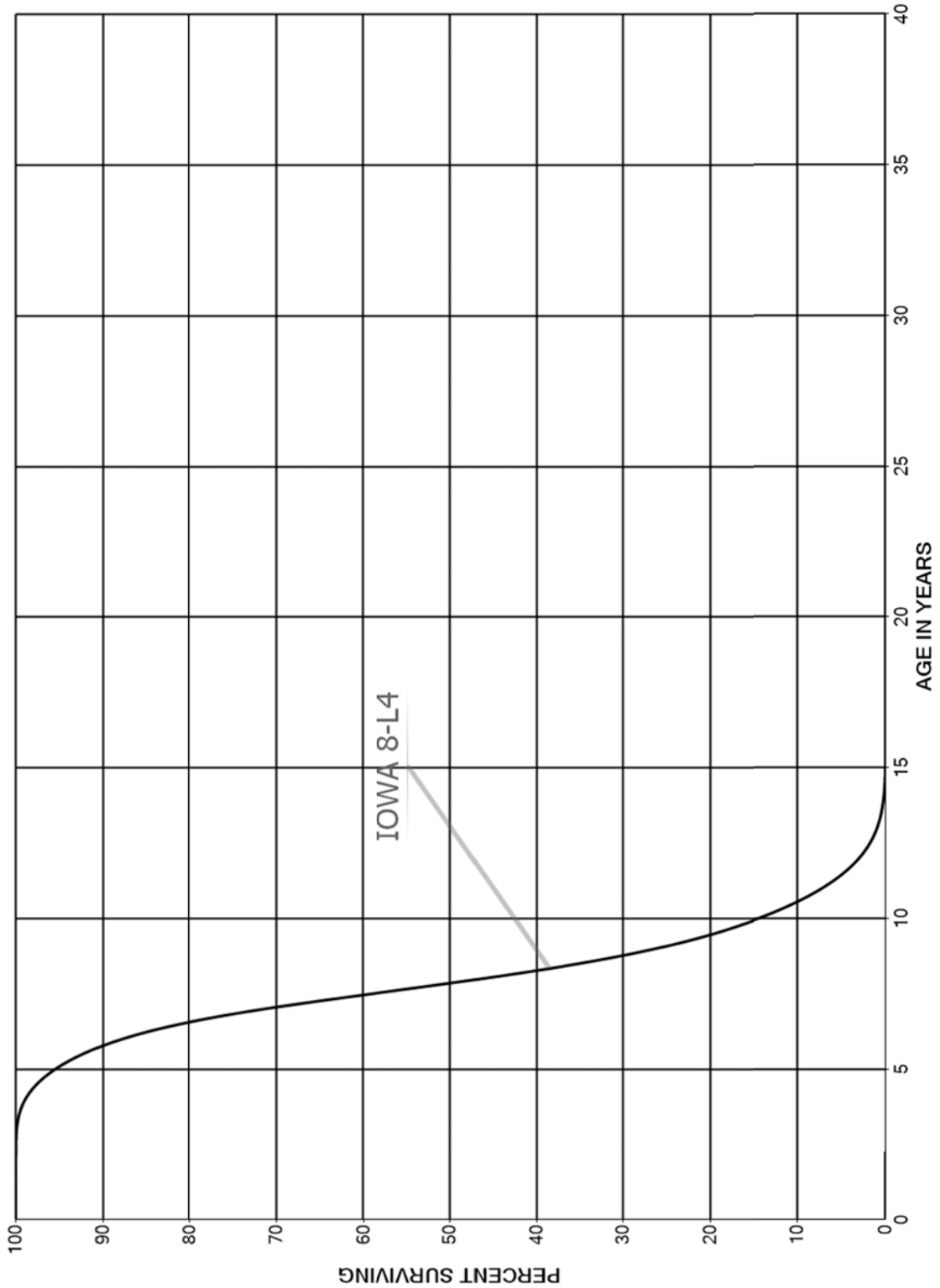
ACCOUNT 392.6 TRANSPORTATION EQUIPMENT - OTHER VEHICLES

ORIGINAL LIFE TABLE, CONT.

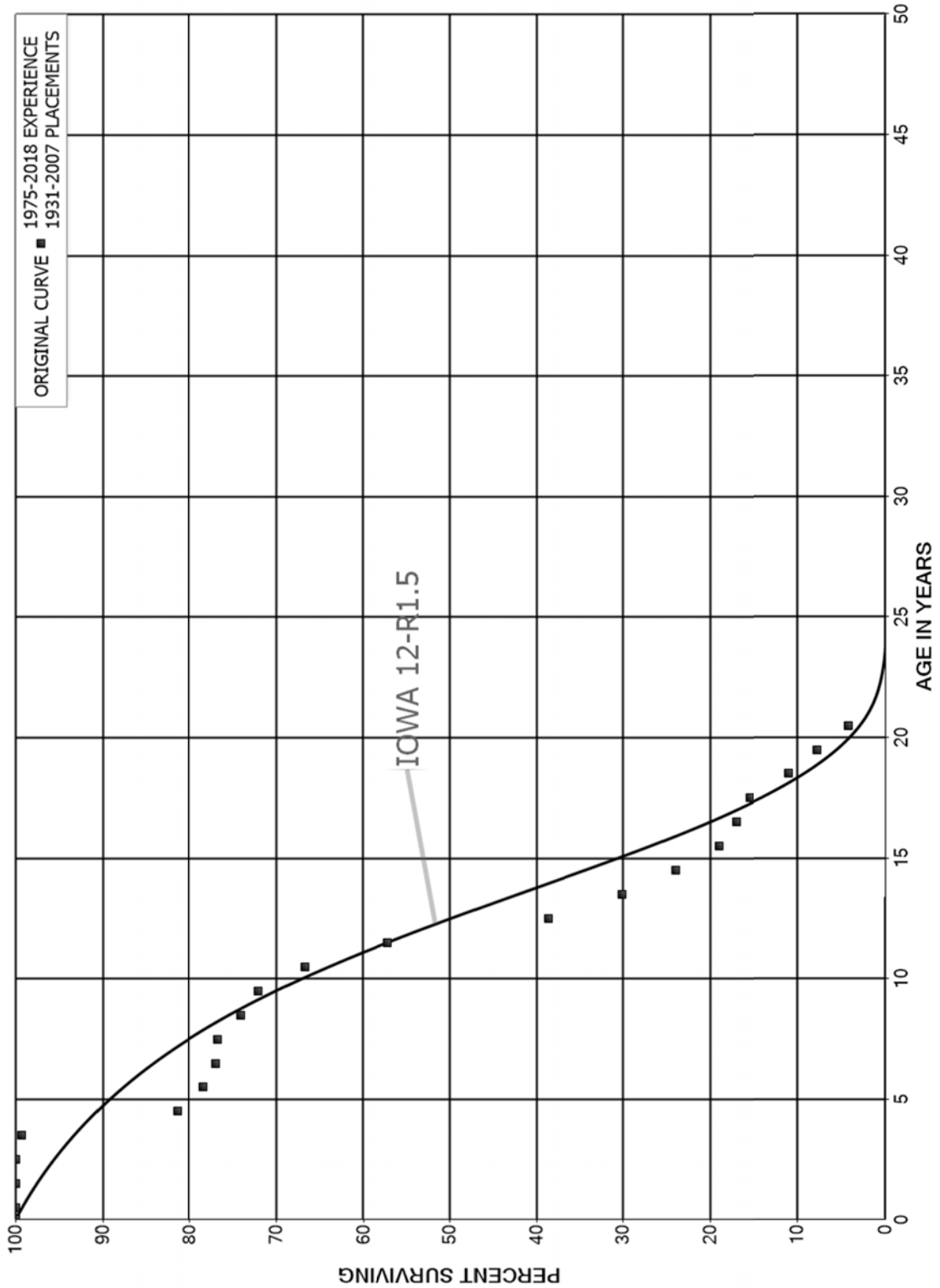
PLACEMENT BAND 1925-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	116,427	507	0.0044	0.9956	6.77
40.5	115,920	1,105	0.0095	0.9905	6.74
41.5	114,815	415	0.0036	0.9964	6.68
42.5	114,400	379	0.0033	0.9967	6.65
43.5	114,022	1,743	0.0153	0.9847	6.63
44.5	108,390	354	0.0033	0.9967	6.53
45.5	105,280		0.0000	1.0000	6.51
46.5	87,956		0.0000	1.0000	6.51
47.5	87,956	158	0.0018	0.9982	6.51
48.5	87,890		0.0000	1.0000	6.50
49.5	88,023	321	0.0036	0.9964	6.50
50.5	87,702	1,279	0.0146	0.9854	6.47
51.5	86,423		0.0000	1.0000	6.38
52.5	86,423	34	0.0004	0.9996	6.38
53.5	1,983		0.0000	1.0000	6.38
54.5	1,983		0.0000	1.0000	6.38
55.5	1,983		0.0000	1.0000	6.38
56.5	1,925		0.0000	1.0000	6.38
57.5	1,925		0.0000	1.0000	6.38
58.5	1,925		0.0000	1.0000	6.38
59.5	1,925	431	0.2241	0.7759	6.38
60.5	1,494	349	0.2334	0.7666	4.95
61.5	1,145		0.0000	1.0000	3.79
62.5	1,145		0.0000	1.0000	3.79
63.5	1,145	91	0.0799	0.9201	3.79
64.5	1,054	133	0.1266	0.8734	3.49
65.5	920		0.0000	1.0000	3.05
66.5	920		0.0000	1.0000	3.05
67.5	920		0.0000	1.0000	3.05
68.5	920		0.0000	1.0000	3.05
69.5	920		0.0000	1.0000	3.05
70.5	920		0.0000	1.0000	3.05
71.5	920		0.0000	1.0000	3.05
72.5					3.05

PECO ENERGY COMPANY
COMMON PLANT
ACCOUNT 392.7 TRANSPORTATION EQUIPMENT - MEDIUM TRUCKS
SMOOTH SURVIVOR CURVE



PECO ENERGY COMPANY
COMMON PLANT
ACCOUNT 396 POWER OPERATED EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 396 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1931-2007 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,161,568		0.0000	1.0000	100.00
0.5	1,166,658		0.0000	1.0000	100.00
1.5	1,464,469		0.0000	1.0000	100.00
2.5	1,682,710	12,459	0.0074	0.9926	100.00
3.5	1,943,469	350,512	0.1804	0.8196	99.26
4.5	1,838,141	66,205	0.0360	0.9640	81.36
5.5	1,995,341	38,863	0.0195	0.9805	78.43
6.5	2,151,118	5,327	0.0025	0.9975	76.90
7.5	2,461,068	84,207	0.0342	0.9658	76.71
8.5	2,397,697	63,814	0.0266	0.9734	74.08
9.5	2,504,489	187,803	0.0750	0.9250	72.11
10.5	2,350,183	334,097	0.1422	0.8578	66.71
11.5	2,020,515	658,859	0.3261	0.6739	57.22
12.5	1,362,407	299,135	0.2196	0.7804	38.56
13.5	1,067,099	218,484	0.2047	0.7953	30.10
14.5	849,779	175,432	0.2064	0.7936	23.93
15.5	674,670	72,946	0.1081	0.8919	18.99
16.5	517,489	45,535	0.0880	0.9120	16.94
17.5	472,956	137,826	0.2914	0.7086	15.45
18.5	371,311	108,635	0.2926	0.7074	10.95
19.5	265,327	120,673	0.4548	0.5452	7.74
20.5	120,391	8,739	0.0726	0.9274	4.22
21.5	117,234	12,332	0.1052	0.8948	3.92
22.5	104,902	5,581	0.0532	0.9468	3.50
23.5	100,365	1,188	0.0118	0.9882	3.32
24.5	99,178	1,045	0.0105	0.9895	3.28
25.5	98,133		0.0000	1.0000	3.24
26.5	103,399		0.0000	1.0000	3.24
27.5	111,434	5,023	0.0451	0.9549	3.24
28.5	106,411	323	0.0030	0.9970	3.10
29.5	106,088	263	0.0025	0.9975	3.09
30.5	105,825	2,105	0.0199	0.9801	3.08
31.5	103,719		0.0000	1.0000	3.02
32.5	98,247		0.0000	1.0000	3.02
33.5	98,247	632	0.0064	0.9936	3.02
34.5	97,615		0.0000	1.0000	3.00
35.5	97,615	35,916	0.3679	0.6321	3.00
36.5	61,698	2,464	0.0399	0.9601	1.90
37.5	53,217	1,386	0.0260	0.9740	1.82
38.5	47,968		0.0000	1.0000	1.77

PECO ENERGY COMPANY
COMMON PLANT

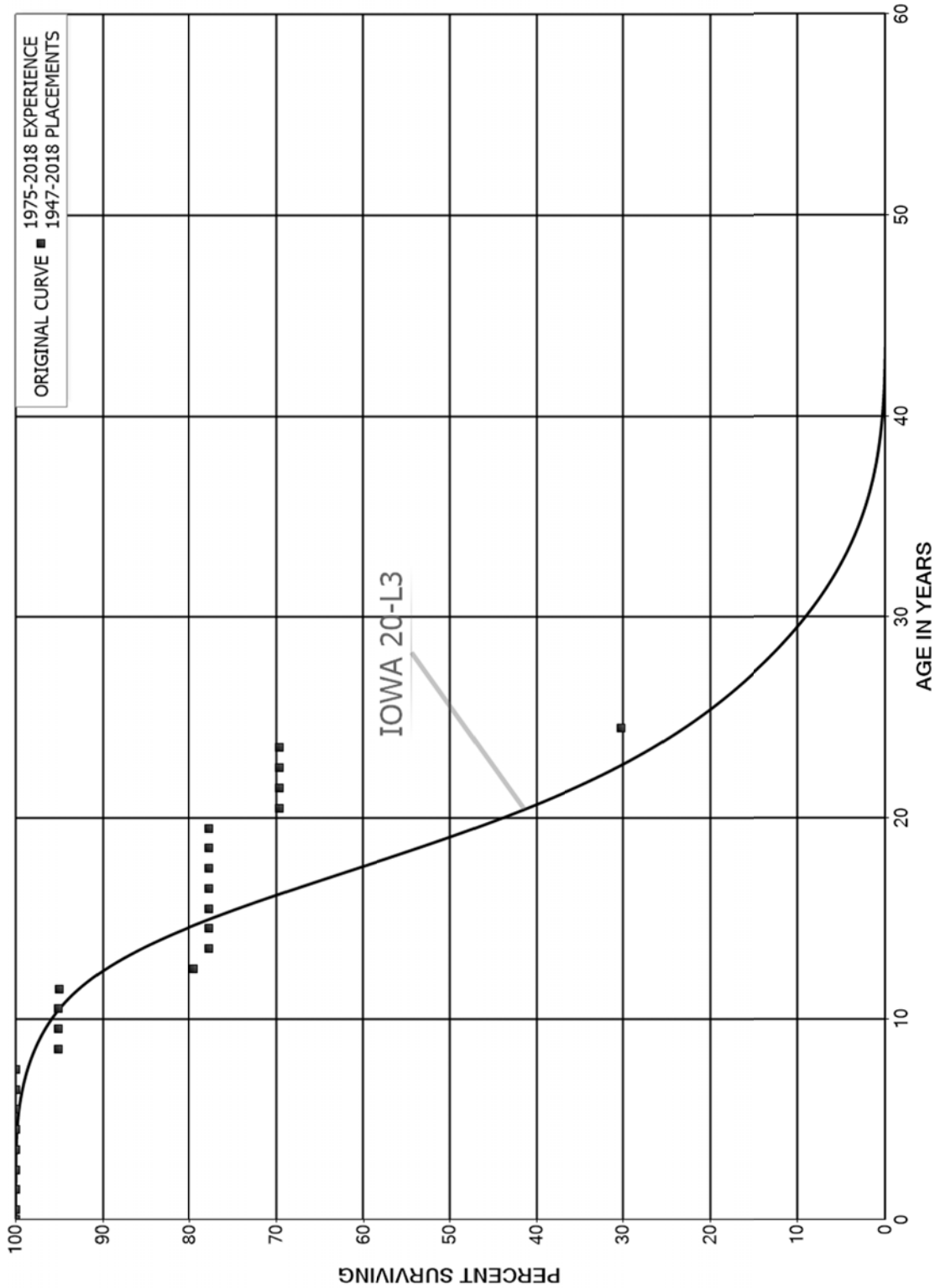
ACCOUNT 396 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1931-2007 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	47,968		0.0000	1.0000	1.77
40.5	47,968		0.0000	1.0000	1.77
41.5	36,141	92	0.0026	0.9974	1.77
42.5	36,049		0.0000	1.0000	1.77
43.5	36,527		0.0000	1.0000	1.77
44.5	36,527	8,034	0.2200	0.7800	1.77
45.5	477		0.0000	1.0000	1.38
46.5	477	477	1.0000		1.38
47.5					

PECO ENERGY COMPANY
COMMON PLANT
ACCOUNT 397 COMMUNICATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 397 COMMUNICATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1947-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	60,440,307		0.0000	1.0000	100.00
0.5	42,261,917		0.0000	1.0000	100.00
1.5	42,040,740		0.0000	1.0000	100.00
2.5	41,574,481		0.0000	1.0000	100.00
3.5	39,684,673		0.0000	1.0000	100.00
4.5	38,595,594		0.0000	1.0000	100.00
5.5	38,560,632	15,352	0.0004	0.9996	100.00
6.5	37,800,235		0.0000	1.0000	99.96
7.5	37,800,235	1,848,387	0.0489	0.9511	99.96
8.5	35,951,847		0.0000	1.0000	95.07
9.5	35,882,581		0.0000	1.0000	95.07
10.5	34,491,688	30,329	0.0009	0.9991	95.07
11.5	27,790,311	4,524,028	0.1628	0.8372	94.99
12.5	15,356,764	338,198	0.0220	0.9780	79.53
13.5	14,974,354		0.0000	1.0000	77.77
14.5	14,974,354		0.0000	1.0000	77.77
15.5	14,330,340		0.0000	1.0000	77.77
16.5	14,279,448		0.0000	1.0000	77.77
17.5	14,157,072		0.0000	1.0000	77.77
18.5	14,157,072		0.0000	1.0000	77.77
19.5	13,125,902	1,378,936	0.1051	0.8949	77.77
20.5	4,348,296		0.0000	1.0000	69.60
21.5	2,028,086		0.0000	1.0000	69.60
22.5	2,013,667		0.0000	1.0000	69.60
23.5	2,013,667	1,140,541	0.5664	0.4336	69.60
24.5	873,126		0.0000	1.0000	30.18
25.5	873,126		0.0000	1.0000	30.18
26.5	873,126		0.0000	1.0000	30.18
27.5	875,112	61,609	0.0704	0.9296	30.18
28.5	813,504	443,566	0.5453	0.4547	28.06
29.5	369,937		0.0000	1.0000	12.76
30.5	369,937		0.0000	1.0000	12.76
31.5	369,937		0.0000	1.0000	12.76
32.5	369,937	351,106	0.9491	0.0509	12.76
33.5	18,831		0.0000	1.0000	0.65
34.5	18,831	16,811	0.8927	0.1073	0.65
35.5	2,020	34	0.0169	0.9831	0.07
36.5	1,986		0.0000	1.0000	0.07
37.5	1,986		0.0000	1.0000	0.07
38.5	1,986		0.0000	1.0000	0.07

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 397 COMMUNICATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1947-2018 EXPERIENCE BAND 1975-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,986		0.0000	1.0000	0.07
40.5	1,986		0.0000	1.0000	0.07
41.5	1,986		0.0000	1.0000	0.07
42.5	1,986	1,986	1.0000		0.07
43.5					

PART VIII. DETAILED DEPRECIATION CALCULATIONS

ELECTRIC PLANT

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2.5						
NET SALVAGE PERCENT.. 0						
1913	110.36	110	110			
1914	35,689.99	35,690	35,690			
1915	425.69	426	426			
1916	233.39	233	233			
1917	440,873.40	440,873	440,873			
1918	109.37	109	109			
1920	145.31	145	145			
1922	2,610.73	2,611	2,611			
1923	21,156.62	21,157	21,157			
1924	1,161.52	1,162	1,162			
1925	192,042.35	192,042	192,042			
1926	83,313.17	82,897	83,313			
1927	100,902.75	100,136	100,903			
1928	37,409.49	36,946	37,409			
1929	177,812.48	174,719	177,812			
1930	76,132.50	74,412	76,132			
1931	91,044.93	88,514	91,045			
1932	74,343.59	71,875	74,344			
1933	2,752.59	2,646	2,753			
1934	1,550.98	1,483	1,551			
1935	2,714.24	2,580	2,714			
1936	155.83	147	156			
1937	192.77	181	192	1	3.01	
1938	8,968.05	8,385	8,879	89	3.25	27
1939	3,127.65	2,909	3,080	48	3.49	14
1940	4,671.21	4,324	4,579	92	3.72	25
1941	16,516.85	15,215	16,111	406	3.94	103
1942	308,134.81	282,498	299,126	9,009	4.16	2,166
1943	44,617.52	40,718	43,115	1,503	4.37	344
1944	130,918.06	118,900	125,899	5,019	4.59	1,093
1945	4,259.31	3,850	4,077	182	4.81	38
1946	19,420.13	17,466	18,494	926	5.03	184
1947	2,656,471.75	2,377,011	2,516,927	139,545	5.26	26,529
1948	154,480.91	137,519	145,614	8,867	5.49	1,615
1949	254,239.89	225,155	238,408	15,832	5.72	2,768
1950	238,850.45	210,427	222,813	16,037	5.95	2,695
1951	92,120.12	80,716	85,467	6,653	6.19	1,075
1952	106,354.98	92,656	98,110	8,245	6.44	1,280
1953	282,800.83	244,962	259,381	23,420	6.69	3,501
1954	544,882.07	469,252	496,873	48,009	6.94	6,918
1955	501,770.94	429,516	454,798	46,973	7.20	6,524

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2.5						
NET SALVAGE PERCENT.. 0						
1956	854,893.79	727,173	769,976	84,918	7.47	11,368
1957	556,860.54	470,547	498,244	58,617	7.75	7,563
1958	560,334.43	470,233	497,912	62,422	8.04	7,764
1959	261,696.90	218,046	230,881	30,816	8.34	3,695
1960	493,061.93	407,664	431,660	61,402	8.66	7,090
1961	717,562.45	588,545	623,188	94,374	8.99	10,498
1962	218,138.04	177,433	187,877	30,261	9.33	3,243
1963	1,121,393.74	904,292	957,521	163,873	9.68	16,929
1964	401,142.23	320,432	339,293	61,849	10.06	6,148
1965	281,624.40	222,765	235,877	45,747	10.45	4,378
1966	1,316,908.86	1,031,140	1,091,835	225,074	10.85	20,744
1967	617,761.39	478,394	506,553	111,208	11.28	9,859
1968	315,597.76	241,622	255,844	59,754	11.72	5,098
1969	1,098,502.02	830,907	879,816	218,686	12.18	17,955
1970	1,228,875.13	917,724	971,743	257,132	12.66	20,311
1971	2,459,264.23	1,812,478	1,919,165	540,099	13.15	41,072
1972	1,349,474.90	980,798	1,038,530	310,945	13.66	22,763
1973	530,606.42	380,020	402,389	128,217	14.19	9,036
1974	514,287.68	362,779	384,133	130,155	14.73	8,836
1975	1,529,871.76	1,062,037	1,124,551	405,321	15.29	26,509
1976	32,238.27	22,006	23,301	8,937	15.87	563
1977	25,031.14	16,791	17,779	7,252	16.46	441
1978	72,816.98	47,957	50,780	22,037	17.07	1,291
1979	1,255,081.71	811,034	858,773	396,309	17.69	22,403
1980	109,595.81	69,440	73,527	36,069	18.32	1,969
1981	514,366.18	319,216	338,006	176,360	18.97	9,297
1982	45,083.79	27,384	28,996	16,088	19.63	820
1983	17,372.39	10,319	10,926	6,446	20.30	318
1984	96,191.98	55,811	59,096	37,096	20.99	1,767
1985	509,388.85	288,518	305,501	203,888	21.68	9,404
1986	130,776.52	72,215	76,466	54,311	22.39	2,426
1987	586,577.17	315,461	334,030	252,547	23.11	10,928
1988	3,459,385.40	1,809,950	1,916,488	1,542,897	23.84	64,719
1989	2,179,465.82	1,108,040	1,173,262	1,006,204	24.58	40,936
1990	853,488.04	421,111	445,899	407,589	25.33	16,091
1991	1,496,690.94	715,718	757,847	738,844	26.09	28,319
1992	948,678.86	439,049	464,893	483,786	26.86	18,011
1993	648,306.26	290,052	307,125	341,181	27.63	12,348
1994	406,913.28	175,624	185,962	220,951	28.42	7,774
1995	309,864.32	128,780	136,360	173,504	29.22	5,938
1996	1,772,920.80	708,459	750,161	1,022,760	30.02	34,069

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2.5						
NET SALVAGE PERCENT.. 0						
1997	107,059.39	41,025	43,440	63,619	30.84	2,063
1998	619,482.91	227,226	240,601	378,882	31.66	11,967
1999	116,951.93	40,957	43,368	73,584	32.49	2,265
2000	130,331.23	43,452	46,010	84,321	33.33	2,530
2002	1,561,754.55	467,589	495,112	1,066,643	35.03	30,449
2003	835,409.26	235,752	249,629	585,780	35.89	16,322
2004	1,765,497.39	467,504	495,022	1,270,475	36.76	34,561
2005	737,477.20	182,304	193,035	544,442	37.64	14,464
2006	2,097,276.25	481,535	509,879	1,587,397	38.52	41,210
2007	13,206,707.48	2,797,181	2,961,830	10,244,877	39.41	259,956
2008	2,647,453.09	513,606	543,838	2,103,615	40.30	52,199
2009	1,873,791.31	329,787	349,199	1,524,592	41.20	37,005
2010	3,764,764.23	594,080	629,049	3,135,715	42.11	74,465
2011	10,738,476.04	1,499,091	1,587,332	9,151,144	43.02	212,718
2012	2,124,938.94	257,968	273,153	1,851,786	43.93	42,153
2013	1,560,836.44	160,454	169,899	1,390,937	44.86	31,006
2014	6,165,690.82	520,384	551,015	5,614,676	45.78	122,645
2015	12,314,987.09	810,326	858,023	11,456,964	46.71	245,279
2016	3,152,170.23	148,152	156,873	2,995,297	47.65	62,860
2017	8,839,859.20	249,284	263,957	8,575,902	48.59	176,495
2018	18,948,752.33	178,118	188,603	18,760,150	49.53	378,763
	131,923,250.00	36,796,312	38,895,666	93,027,584		2,458,965

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.8 1.86

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R3						
NET SALVAGE PERCENT.. 0						
1916	19,723.91	19,724	19,724			
1917	1,954.83	1,955	1,955			
1919	411.69	412	412			
1920	53,327.35	53,327	53,327			
1921	2,267.30	2,267	2,267			
1922	3,992.55	3,993	3,993			
1923	697,046.71	697,047	697,047			
1924	686,040.46	686,040	686,040			
1925	254,381.14	254,381	254,381			
1926	71,623.80	71,624	71,624			
1927	31,523.36	31,523	31,523			
1928	55,561.57	55,562	55,562			
1929	1,039,607.66	1,039,015	1,039,608			
1930	219,815.46	218,281	219,815			
1931	217,971.54	215,750	217,972			
1932	1,721,326.07	1,696,969	1,721,326			
1933	6,421.78	6,304	6,422			
1934	14.16	14	14			
1936	766.22	742	766			
1937	36,532.37	35,202	36,532			
1938	35,056.43	33,615	35,056			
1939	63,906.74	60,977	63,907			
1940	80,061.14	75,998	80,061			
1941	154,531.61	145,960	154,532			
1942	1,150,005.92	1,080,569	1,150,006			
1943	241,826.50	226,086	241,826			
1944	349,871.15	325,380	349,871			
1945	878,875.23	813,039	878,875			
1946	169,211.45	155,707	169,211			
1947	4,054,752.66	3,711,234	4,054,753			
1948	665,662.06	606,005	665,662			
1949	1,508,517.35	1,365,917	1,508,517			
1950	1,728,765.13	1,556,874	1,728,765			
1951	1,794,800.24	1,607,190	1,794,800			
1952	1,247,334.64	1,110,602	1,247,335			
1953	3,823,909.61	3,384,504	3,823,910			
1954	3,822,790.43	3,362,603	3,822,790			
1955	2,867,188.36	2,505,808	2,867,188			
1956	5,239,141.04	4,547,155	5,239,141			
1957	4,151,175.89	3,577,857	4,142,342	8,834	7.32	1,207
1958	5,769,400.69	4,935,549	5,714,240	55,161	7.66	7,201

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R3						
NET SALVAGE PERCENT.. 0						
1959	5,014,860.60	4,256,965	4,928,594	86,267	8.01	10,770
1960	5,367,345.37	4,518,714	5,231,640	135,705	8.38	16,194
1961	5,420,446.22	4,524,555	5,238,403	182,043	8.76	20,781
1962	3,295,234.19	2,725,719	3,155,761	139,473	9.16	15,226
1963	5,768,224.78	4,726,656	5,472,389	295,836	9.57	30,913
1964	4,274,158.18	3,466,898	4,013,877	260,281	10.01	26,002
1965	3,546,646.70	2,846,681	3,295,807	250,840	10.46	23,981
1966	3,981,255.05	3,160,201	3,658,792	322,463	10.93	29,503
1967	6,916,562.39	5,426,251	6,282,361	634,201	11.42	55,534
1968	7,495,911.20	5,810,006	6,726,662	769,249	11.92	64,534
1969	14,778,938.47	11,307,218	13,091,179	1,687,759	12.45	135,563
1970	11,966,081.42	9,033,315	10,458,518	1,507,563	12.99	116,056
1971	16,159,890.85	12,028,453	13,926,205	2,233,686	13.55	164,848
1972	16,060,116.40	11,781,380	13,640,151	2,419,965	14.12	171,386
1973	7,689,761.65	5,555,468	6,431,965	1,257,797	14.71	85,506
1974	15,189,836.75	10,799,063	12,502,852	2,686,985	15.32	175,391
1975	9,378,514.06	6,556,144	7,590,519	1,787,995	15.95	112,100
1976	544,499.52	374,060	433,076	111,424	16.59	6,716
1977	2,829,535.42	1,909,144	2,210,353	619,182	17.24	35,915
1978	1,199,458.17	794,137	919,430	280,028	17.91	15,635
1979	3,910,818.32	2,539,099	2,939,697	971,121	18.59	52,239
1980	2,384,218.62	1,516,911	1,756,237	627,982	19.28	32,572
1981	4,735,955.93	2,949,695	3,415,074	1,320,882	19.99	66,077
1982	1,636,386.12	996,968	1,154,262	482,124	20.71	23,280
1983	4,157,966.42	2,475,944	2,866,578	1,291,388	21.44	60,233
1984	7,868,086.86	4,573,876	5,295,505	2,572,582	22.19	115,934
1985	6,607,722.96	3,747,702	4,338,984	2,268,739	22.94	98,899
1986	8,217,153.49	4,541,128	5,257,590	2,959,563	23.71	124,823
1987	15,280,321.36	8,222,494	9,519,772	5,760,549	24.48	235,317
1988	26,562,567.34	13,897,801	16,090,483	10,472,084	25.27	414,408
1989	29,673,080.48	15,082,827	17,462,473	12,210,607	26.06	468,557
1990	38,027,819.26	18,748,475	21,706,458	16,321,361	26.87	607,419
1991	24,173,073.11	11,548,444	13,370,464	10,802,609	27.68	390,268
1992	33,496,450.13	15,478,040	17,920,040	15,576,410	28.51	546,349
1993	29,014,628.46	12,952,710	14,996,284	14,018,344	29.34	477,790
1994	7,148,959.11	3,076,769	3,562,197	3,586,762	30.19	118,806
1995	15,338,004.17	6,355,149	7,357,813	7,980,191	31.04	257,094
1996	18,455,854.64	7,347,460	8,506,683	9,949,172	31.90	311,886
1997	7,429,774.91	2,835,945	3,283,377	4,146,398	32.77	126,530
1998	35,609,773.78	13,000,772	15,051,928	20,557,846	33.65	610,932
1999	13,379,790.29	4,662,723	5,398,370	7,981,420	34.53	231,145

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R3						
NET SALVAGE PERCENT.. 0						
2000	10,666,831.84	3,536,161	4,094,068	6,572,764	35.43	185,514
2001	35,132,703.51	11,050,289	12,793,714	22,338,990	36.33	614,891
2002	7,392,867.06	2,198,343	2,545,180	4,847,687	37.24	130,174
2003	16,840,045.04	4,718,412	5,462,845	11,377,200	38.15	298,223
2004	17,268,076.64	4,538,569	5,254,628	12,013,449	39.07	307,485
2005	10,320,616.69	2,531,441	2,930,831	7,389,786	40.00	184,745
2006	31,989,633.33	7,279,241	8,427,701	23,561,932	40.94	575,523
2007	32,303,274.23	6,777,550	7,846,857	24,456,417	41.88	583,964
2008	39,903,761.09	7,664,714	8,873,990	31,029,771	42.82	724,656
2009	28,532,106.95	4,968,866	5,752,813	22,779,294	43.77	520,432
2010	28,612,055.71	4,464,625	5,169,017	23,443,039	44.73	524,101
2011	50,824,594.11	7,009,728	8,115,666	42,708,928	45.69	934,754
2012	17,469,875.70	2,093,066	2,423,293	15,046,583	46.65	322,542
2013	19,650,019.68	1,994,673	2,309,376	17,340,644	47.62	364,146
2014	28,993,609.40	2,412,558	2,793,192	26,200,417	48.59	539,214
2015	37,626,563.60	2,435,191	2,819,396	34,807,168	49.57	702,182
2016	43,302,272.71	2,010,091	2,327,227	40,975,046	50.54	810,745
2017	43,567,728.54	1,216,411	1,408,327	42,159,402	51.52	818,311
2018	37,788,934.82	349,548	404,697	37,384,238	52.51	711,945
	1,063,088,348.00	387,680,198	447,064,719	616,023,629		16,545,067

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.2 1.56

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R2						
NET SALVAGE PERCENT.. 0						
1928	6,128.64	5,888	4,603	1,526	2.08	734
1929	7,383.57	7,056	5,516	1,868	2.35	795
1930	7,021.22	6,673	5,216	1,805	2.63	686
1931	7,078.60	6,690	5,230	1,849	2.91	635
1932	4,805.40	4,516	3,530	1,275	3.19	400
1933	6,835.41	6,387	4,993	1,842	3.48	529
1934	8,439.24	7,839	6,128	2,311	3.77	613
1935	17,280.97	15,960	12,476	4,805	4.05	1,186
1936	20,633.34	18,944	14,808	5,825	4.34	1,342
1937	8,158.73	7,446	5,820	2,339	4.63	505
1938	18,157.79	16,472	12,876	5,282	4.92	1,074
1939	3,038.50	2,739	2,141	898	5.22	172
1942	117,169.28	103,705	81,066	36,103	6.09	5,928
1943	55,103.03	48,459	37,880	17,223	6.39	2,695
1944	73,404.16	64,152	50,147	23,257	6.68	3,482
1945	80,972.62	70,309	54,960	26,013	6.98	3,727
1946	95,698.86	82,554	64,532	31,167	7.28	4,281
1947	100,146.18	85,804	67,072	33,074	7.59	4,358
1948	193,281.85	164,471	128,566	64,716	7.90	8,192
1949	235,358.26	198,857	155,445	79,913	8.22	9,722
1950	214,782.62	180,175	140,842	73,941	8.54	8,658
1951	392,981.48	327,212	255,780	137,201	8.87	15,468
1953	289,223.26	237,108	185,346	103,877	9.55	10,877
1954	656,837.63	534,147	417,540	239,298	9.90	24,172
1955	807,815.55	651,285	509,106	298,710	10.27	29,086
1956	1,113,237.29	889,755	695,516	417,721	10.64	39,259
1957	1,110,107.51	879,494	687,495	422,613	11.01	38,384
1958	1,746,050.12	1,370,492	1,071,306	674,744	11.40	59,188
1959	1,555,699.79	1,209,339	945,333	610,367	11.80	51,726
1960	1,943,677.03	1,495,893	1,169,331	774,346	12.21	63,419
1961	2,309,159.78	1,758,887	1,374,912	934,248	12.63	73,971
1962	2,029,545.63	1,529,060	1,195,258	834,288	13.07	63,832
1963	2,016,294.15	1,502,321	1,174,356	841,938	13.51	62,320
1964	2,130,788.40	1,569,539	1,226,900	903,888	13.96	64,748
1966	1,416,442.20	1,018,238	795,951	620,491	14.90	41,644
1967	1,701,333.47	1,207,300	943,740	757,593	15.39	49,226
1968	2,330,284.19	1,631,642	1,275,445	1,054,839	15.89	66,384
1969	4,142,372.81	2,860,598	2,236,113	1,906,260	16.40	116,235
1970	4,147,556.61	2,823,449	2,207,074	1,940,483	16.92	114,686
1971	2,843,700.17	1,907,412	1,491,013	1,352,687	17.45	77,518
1972	2,847,814.59	1,881,181	1,470,509	1,377,306	17.99	76,560

PECO ENERGY COMPANY
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ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R2						
NET SALVAGE PERCENT.. 0						
1973	3,179,341.51	2,067,176	1,615,900	1,563,442	18.54	84,328
1974	3,915,712.71	2,503,824	1,957,225	1,958,488	19.11	102,485
1975	2,618,333.57	1,646,094	1,286,742	1,331,592	19.68	67,662
1976	2,536,673.36	1,566,523	1,224,542	1,312,131	20.27	64,733
1977	3,152,092.12	1,910,893	1,493,734	1,658,358	20.87	79,461
1978	3,289,044.50	1,956,061	1,529,042	1,760,002	21.48	81,937
1979	3,064,064.23	1,786,993	1,396,882	1,667,182	22.09	75,472
1980	3,282,962.87	1,875,622	1,466,163	1,816,800	22.72	79,965
1981	3,765,510.70	2,105,862	1,646,140	2,119,371	23.36	90,726
1982	4,514,547.88	2,469,367	1,930,290	2,584,258	24.01	107,633
1983	4,455,137.23	2,382,251	1,862,192	2,592,945	24.66	105,148
1984	6,203,614.86	3,238,783	2,531,738	3,671,877	25.33	144,962
1985	7,871,568.83	4,010,013	3,134,604	4,736,965	26.00	182,191
1986	9,244,486.49	4,589,148	3,587,311	5,657,175	26.69	211,959
1987	11,591,943.06	5,603,545	4,380,259	7,211,684	27.38	263,392
1988	10,296,519.85	4,839,364	3,782,903	6,513,617	28.09	231,884
1989	12,854,878.00	5,869,537	4,588,184	8,266,694	28.80	287,038
1990	11,323,025.23	5,016,327	3,921,234	7,401,791	29.52	250,738
1991	8,921,233.29	3,831,045	2,994,706	5,926,527	30.24	195,983
1992	12,301,830.95	5,111,042	3,995,273	8,306,558	30.98	268,126
1993	13,308,810.66	5,343,621	4,177,078	9,131,733	31.72	287,886
1994	10,010,384.41	3,875,721	3,029,629	6,980,755	32.48	214,925
1995	10,006,675.28	3,730,789	2,916,337	7,090,338	33.24	213,307
1996	17,420,203.63	6,244,969	4,881,657	12,538,547	34.00	368,781
1997	13,003,882.34	4,470,345	3,494,443	9,509,439	34.78	273,417
1998	15,635,729.72	5,145,093	4,021,890	11,613,840	35.56	326,598
1999	20,696,796.93	6,501,899	5,082,498	15,614,299	36.35	429,554
2000	7,941,420.05	2,374,961	1,856,494	6,084,926	37.15	163,793
2001	38,401,160.29	10,904,393	8,523,902	29,877,258	37.95	787,280
2002	27,463,665.04	7,378,938	5,768,074	21,695,591	38.76	559,742
2003	28,989,687.85	7,340,479	5,738,011	23,251,677	39.58	587,460
2004	10,760,680.05	2,558,244	1,999,765	8,760,915	40.40	216,854
2005	22,118,843.42	4,912,153	3,839,802	18,279,041	41.23	443,343
2006	21,406,787.96	4,414,722	3,450,963	17,955,825	42.07	426,808
2007	16,319,265.04	3,106,862	2,428,616	13,890,649	42.91	323,716
2008	21,093,352.80	3,677,415	2,874,615	18,218,738	43.76	416,333
2009	15,492,335.54	2,452,437	1,917,056	13,575,280	44.61	304,310
2010	23,666,449.39	3,362,529	2,628,470	21,037,979	45.47	462,678
2011	27,213,366.09	3,419,632	2,673,107	24,540,259	46.34	529,570
2012	22,828,368.63	2,493,999	1,949,545	20,878,824	47.21	442,254
2013	21,132,259.08	1,957,692	1,530,317	19,601,942	48.09	407,610

PECO ENERGY COMPANY
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ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R2						
NET SALVAGE PERCENT.. 0						
2014	27,221,935.12	2,069,956	1,618,073	25,603,862	48.97	522,848
2015	25,413,407.32	1,505,744	1,177,031	24,236,376	49.86	486,089
2016	26,168,651.21	1,110,859	868,352	25,300,299	50.75	498,528
2017	28,925,756.08	736,739	575,905	28,349,851	51.65	548,884
2018	55,121,462.84	467,981	365,818	54,755,645	52.55	1,041,972
	734,955,657.94	194,327,090	151,904,383	583,051,275		15,458,780
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					37.7	2.10

PECO ENERGY COMPANY
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ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 52-R2.5						
NET SALVAGE PERCENT.. 0						
1931	51.93	50	42	10	2.39	4
1932	27.44	26	22	5	2.67	2
1933	107.00	101	85	22	2.93	8
1934	182.21	171	143	39	3.19	12
1935	68.71	64	54	15	3.43	4
1936	91.71	85	71	21	3.67	6
1937	175.72	163	137	39	3.89	10
1938	358.75	330	276	83	4.12	20
1939	6,964.43	6,385	5,348	1,616	4.33	373
1940	3,155.40	2,879	2,412	743	4.55	163
1942	14,663.11	13,256	11,104	3,559	4.99	713
1943	8,169.75	7,351	6,158	2,012	5.21	386
1944	15,298.16	13,698	11,474	3,824	5.44	703
1945	14,984.00	13,353	11,185	3,799	5.66	671
1946	27,554.91	24,434	20,467	7,088	5.89	1,203
1947	23,881.10	21,066	17,646	6,235	6.13	1,017
1948	46,410.38	40,725	34,113	12,297	6.37	1,930
1949	142,011.39	123,959	103,834	38,177	6.61	5,776
1950	203,704.07	176,831	148,122	55,582	6.86	8,102
1951	370,492.75	319,835	267,909	102,584	7.11	14,428
1952	63,992.40	54,923	46,006	17,986	7.37	2,440
1953	131,780.63	112,419	94,168	37,613	7.64	4,923
1954	66,310.48	56,223	47,095	19,215	7.91	2,429
1955	201,750.62	169,975	142,379	59,372	8.19	7,249
1956	608,859.07	509,451	426,741	182,118	8.49	21,451
1957	809,536.20	672,692	563,479	246,057	8.79	27,993
1958	988,133.77	815,023	682,703	305,431	9.11	33,527
1959	1,625,854.77	1,330,388	1,114,398	511,457	9.45	54,122
1960	2,232,316.87	1,812,039	1,517,852	714,465	9.79	72,979
1961	3,457,067.55	2,782,283	2,330,575	1,126,493	10.15	110,985
1962	3,024,443.22	2,411,993	2,020,402	1,004,041	10.53	95,351
1963	4,061,950.20	3,208,941	2,687,965	1,373,985	10.92	125,823
1964	5,123,133.52	4,006,905	3,356,378	1,766,756	11.33	155,936
1965	2,362,139.24	1,827,941	1,531,172	830,967	11.76	70,660
1966	2,918,768.50	2,233,967	1,871,279	1,047,490	12.20	85,860
1967	3,199,246.25	2,420,358	2,027,409	1,171,837	12.66	92,562
1968	3,591,051.57	2,684,311	2,248,509	1,342,543	13.13	102,250
1969	7,644,659.82	5,640,842	4,725,043	2,919,617	13.63	214,205
1970	7,562,731.25	5,507,710	4,613,525	2,949,206	14.13	208,719
1971	5,143,178.89	3,693,214	3,093,615	2,049,564	14.66	139,807
1972	4,625,769.77	3,273,611	2,742,135	1,883,635	15.20	123,923

PECO ENERGY COMPANY
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 52-R2.5						
NET SALVAGE PERCENT.. 0						
1973	6,155,406.95	4,289,826	3,593,366	2,562,041	15.76	162,566
1974	6,264,336.63	4,297,084	3,599,446	2,664,891	16.33	163,190
1975	3,964,030.47	2,674,214	2,240,051	1,723,979	16.92	101,890
1976	4,312,675.48	2,859,649	2,395,381	1,917,294	17.52	109,435
1977	3,876,154.32	2,524,733	2,114,839	1,761,315	18.13	97,149
1978	4,529,834.93	2,895,606	2,425,500	2,104,335	18.76	112,171
1979	5,311,826.07	3,330,090	2,789,445	2,522,381	19.40	130,020
1980	6,237,116.55	3,831,024	3,209,052	3,028,065	20.06	150,950
1981	5,864,323.14	3,527,625	2,954,910	2,909,413	20.72	140,416
1982	5,638,670.52	3,318,132	2,779,428	2,859,243	21.40	133,609
1983	5,518,075.34	3,173,942	2,658,648	2,859,427	22.09	129,444
1984	7,751,943.93	4,354,499	3,647,540	4,104,404	22.79	180,097
1985	8,624,151.87	4,726,725	3,959,334	4,664,818	23.50	198,503
1986	10,393,799.02	5,552,679	4,651,193	5,742,606	24.22	237,102
1987	15,168,581.92	7,890,545	6,609,503	8,559,079	24.95	343,049
1988	14,405,287.05	7,285,762	6,102,908	8,302,379	25.70	323,050
1989	23,316,119.82	11,456,375	9,596,415	13,719,705	26.45	518,703
1990	19,547,812.44	9,319,029	7,806,071	11,741,741	27.21	431,523
1991	13,949,276.32	6,443,450	5,397,346	8,551,930	27.98	305,644
1992	19,468,220.43	8,700,737	7,288,159	12,180,061	28.76	423,507
1993	21,378,929.13	9,233,987	7,734,835	13,644,094	29.54	461,885
1994	20,502,549.40	8,540,132	7,153,629	13,348,920	30.34	439,978
1995	26,686,036.90	10,705,104	8,967,114	17,718,923	31.14	569,008
1996	36,293,474.55	13,986,779	11,716,005	24,577,470	31.96	769,007
1997	21,772,230.26	8,047,452	6,740,936	15,031,294	32.78	458,551
1998	33,965,812.00	12,012,009	10,061,841	23,903,971	33.61	711,216
1999	18,051,221.89	6,092,287	5,103,195	12,948,027	34.45	375,850
2000	2,923,732.58	939,541	787,005	2,136,728	35.29	60,548
2001	22,160,281.47	6,758,886	5,661,571	16,498,710	36.14	456,522
2002	23,940,403.17	6,905,849	5,784,674	18,155,729	37.00	490,695
2003	19,604,165.95	5,327,040	4,462,187	15,141,979	37.87	399,841
2004	10,601,050.60	2,703,268	2,264,388	8,336,663	38.74	215,195
2005	61,581,977.11	14,661,437	12,281,131	49,300,846	39.62	1,244,342
2006	35,483,081.42	7,847,083	6,573,097	28,909,984	40.50	713,827
2007	40,053,206.46	8,172,456	6,845,646	33,207,560	41.39	802,309
2008	51,069,825.06	9,536,268	7,988,041	43,081,784	42.29	1,018,723
2009	43,923,524.86	7,441,524	6,233,382	37,690,143	43.19	872,659
2010	47,121,316.87	7,158,670	5,996,449	41,124,868	44.10	932,537
2011	50,388,559.98	6,773,230	5,673,586	44,714,974	45.01	993,445
2012	45,372,380.63	5,296,318	4,436,453	40,935,928	45.93	891,268
2013	35,402,237.09	3,506,238	2,936,995	32,465,242	46.85	692,961

PECO ENERGY COMPANY
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 52-R2.5						
NET SALVAGE PERCENT.. 0						
2014	71,806,790.19	5,827,121	4,881,079	66,925,711	47.78	1,400,706
2015	52,918,975.45	3,348,184	2,804,601	50,114,374	48.71	1,028,831
2016	56,975,356.33	2,574,716	2,156,707	54,818,649	49.65	1,104,102
2017	72,791,503.41	1,987,936	1,665,192	71,126,311	50.58	1,406,214
2018	93,217,288.53	842,684	705,873	92,511,415	51.53	1,795,292
	1,266,604,582.00	324,667,896	271,957,577	994,647,005		26,486,255
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					37.6	2.09

PECO ENERGY COMPANY
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ACCOUNT 366 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1905	2,086,425.36	2,086,425	2,086,425			
1906	64,530.09	64,530	64,530			
1907	78,722.20	78,722	78,722			
1908	114,758.05	114,758	114,758			
1909	43,244.59	43,245	43,245			
1910	64,341.07	64,341	64,341			
1911	361,050.02	361,050	361,050			
1912	105,687.74	105,234	105,688			
1913	249,203.64	248,135	249,204			
1914	109,582.06	108,783	109,582			
1915	16,565.16	16,400	16,565			
1916	108,233.24	106,873	108,233			
1917	103,788.14	102,142	103,788			
1918	64,445.22	63,257	64,445			
1919	265,385.20	259,661	265,385			
1920	161,393.98	157,429	161,394			
1921	206,750.18	201,021	206,750			
1922	231,306.65	224,104	231,307			
1923	482,079.74	465,549	482,080			
1924	1,065,780.71	1,025,430	1,065,781			
1925	1,235,956.02	1,185,109	1,235,956			
1926	1,031,811.44	985,679	1,031,811			
1927	1,918,038.11	1,825,416	1,918,038			
1928	1,546,507.54	1,466,089	1,546,508			
1929	339,828.53	320,897	339,829			
1930	709,962.10	667,769	709,962			
1931	943,899.32	884,302	943,899			
1932	664,133.16	619,636	664,133			
1933	737,546.87	685,284	737,547			
1934	788,587.18	729,672	788,587			
1935	138,749.30	127,828	138,749			
1936	101,117.20	92,754	101,117			
1937	57,410.52	52,432	57,411			
1938	60,656.58	55,137	60,453	204	6.37	32
1939	53,679.74	48,565	53,247	433	6.67	65
1940	51,511.06	46,367	50,838	673	6.99	96
1941	426,139.87	381,638	418,434	7,706	7.31	1,054
1942	1,604,221.22	1,428,896	1,566,665	37,556	7.65	4,909
1943	53,654.70	47,523	52,105	1,550	8.00	194
1944	113,733.13	100,150	109,806	3,927	8.36	470
1945	132,340.48	115,798	126,963	5,377	8.75	615

PECO ENERGY COMPANY
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ACCOUNT 366 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1946	161,201.35	140,131	153,642	7,559	9.15	826
1947	2,234,099.45	1,928,676	2,114,632	119,467	9.57	12,483
1948	1,649,396.86	1,413,302	1,549,568	99,829	10.02	9,963
1949	1,633,924.46	1,389,310	1,523,262	110,662	10.48	10,559
1950	2,047,822.12	1,726,908	1,893,411	154,411	10.97	14,076
1951	2,312,975.58	1,933,648	2,120,084	192,892	11.48	16,802
1952	800,141.39	662,861	726,772	73,369	12.01	6,109
1953	991,906.72	813,790	892,253	99,654	12.57	7,928
1954	1,354,169.21	1,099,775	1,205,812	148,357	13.15	11,282
1955	1,122,098.41	901,528	988,450	133,648	13.76	9,713
1956	2,961,037.30	2,352,751	2,579,595	381,442	14.38	26,526
1957	1,715,769.20	1,347,617	1,477,550	238,219	15.02	15,860
1958	908,779.33	705,340	773,346	135,433	15.67	8,643
1959	1,619,422.75	1,241,628	1,361,341	258,082	16.33	15,804
1960	1,605,015.57	1,214,997	1,332,143	272,873	17.01	16,042
1961	2,436,334.96	1,820,283	1,995,788	440,547	17.70	24,890
1962	2,007,724.27	1,480,275	1,622,998	384,726	18.39	20,920
1963	2,552,021.08	1,855,677	2,034,595	517,426	19.10	27,090
1964	4,660,850.25	3,341,830	3,664,038	996,812	19.81	50,319
1965	3,918,599.49	2,768,765	3,035,720	882,879	20.54	42,983
1966	3,584,238.66	2,494,630	2,735,154	849,085	21.28	39,901
1967	5,216,343.82	3,574,708	3,919,369	1,296,975	22.03	58,873
1968	6,672,529.15	4,501,088	4,935,067	1,737,462	22.78	76,271
1969	7,202,012.80	4,779,040	5,239,819	1,962,194	23.55	83,320
1970	9,417,214.45	6,144,073	6,736,463	2,680,751	24.33	110,183
1971	6,712,226.78	4,303,477	4,718,403	1,993,824	25.12	79,372
1972	5,374,743.81	3,383,777	3,710,029	1,664,715	25.93	64,200
1973	3,792,506.87	2,343,769	2,569,747	1,222,760	26.74	45,728
1974	4,488,890.29	2,721,569	2,983,973	1,504,917	27.56	54,605
1975	2,405,595.97	1,429,958	1,567,830	837,766	28.39	29,509
1976	4,655,836.55	2,711,699	2,973,152	1,682,685	29.23	57,567
1977	1,365,480.96	778,515	853,577	511,904	30.09	17,012
1978	1,027,890.85	573,419	628,706	399,185	30.95	12,898
1979	1,992,470.74	1,086,753	1,191,534	800,937	31.82	25,171
1980	1,966,238.68	1,047,730	1,148,749	817,490	32.70	25,000
1981	2,608,397.43	1,356,732	1,487,543	1,120,854	33.59	33,369
1982	2,324,132.80	1,179,335	1,293,042	1,031,091	34.48	29,904
1983	2,638,380.07	1,304,494	1,430,269	1,208,111	35.39	34,137
1984	3,132,583.89	1,508,120	1,653,528	1,479,056	36.30	40,745
1985	2,741,128.83	1,283,643	1,407,407	1,333,722	37.22	35,833
1986	2,947,087.25	1,341,337	1,470,664	1,476,423	38.14	38,711

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 366 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1987	6,228,135.89	2,751,964	3,017,299	3,210,837	39.07	82,182
1988	5,187,654.37	2,222,547	2,436,837	2,750,817	40.01	68,753
1989	5,767,356.95	2,393,453	2,624,222	3,143,135	40.95	76,755
1990	17,885,615.82	7,179,823	7,872,077	10,013,539	41.90	238,987
1991	4,243,028.01	1,645,064	1,803,675	2,439,353	42.86	56,914
1992	3,738,267.99	1,398,636	1,533,488	2,204,780	43.81	50,326
1993	7,757,650.12	2,795,004	3,064,489	4,693,161	44.78	104,805
1994	3,397,340.62	1,177,416	1,290,938	2,106,403	45.74	46,052
1995	5,302,310.29	1,764,132	1,934,224	3,368,086	46.71	72,106
1996	5,185,142.56	1,653,335	1,812,744	3,372,399	47.68	70,730
1997	5,522,581.40	1,683,614	1,845,942	3,676,639	48.66	75,558
1998	3,094,790.60	900,151	986,940	2,107,851	49.64	42,463
1999	2,533,609.72	701,455	769,087	1,764,523	50.62	34,858
2000	920,574.29	241,982	265,313	655,261	51.60	12,699
2001	14,913,935.19	3,709,245	4,066,878	10,847,057	52.59	206,257
2002	7,197,875.43	1,689,413	1,852,300	5,345,575	53.57	99,787
2003	9,069,536.53	2,000,468	2,193,346	6,876,191	54.56	126,030
2004	4,264,822.10	880,387	965,271	3,299,551	55.55	59,398
2005	5,710,760.24	1,098,122	1,203,999	4,506,761	56.54	79,709
2006	5,013,912.06	892,476	978,526	4,035,386	57.54	70,132
2007	11,781,013.65	1,930,437	2,116,563	9,664,451	58.53	165,120
2008	4,876,757.12	730,099	800,493	4,076,264	59.52	68,486
2009	12,644,104.69	1,712,391	1,877,494	10,766,611	60.52	177,902
2010	7,734,725.92	936,985	1,027,326	6,707,400	61.52	109,028
2011	16,308,663.60	1,745,027	1,913,276	14,395,388	62.51	230,289
2012	7,897,626.85	732,189	802,784	7,094,843	63.51	111,712
2013	8,980,501.51	704,341	772,251	8,208,251	64.51	127,240
2014	14,049,937.16	901,163	988,050	13,061,887	65.51	199,388
2015	20,316,139.97	1,015,807	1,113,748	19,202,392	66.50	288,758
2016	26,585,392.63	949,364	1,040,898	25,544,495	67.50	378,437
2017	14,380,765.32	308,180	337,894	14,042,871	68.50	205,005
2018	23,183,772.01	165,532	181,492	23,002,280	69.50	330,968
	431,326,278.12	148,361,190	161,824,220	269,502,058		5,415,396

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 49.8 1.26

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 54-S0.5						
NET SALVAGE PERCENT.. 0						
1924	1,888.94	1,726	1,193	696	4.66	149
1925	96,833.49	87,885	60,756	36,077	4.99	7,230
1926	98,001.31	88,329	61,063	36,938	5.33	6,930
1927	109,480.08	98,005	67,752	41,728	5.66	7,372
1928	106,672.86	94,820	65,551	41,122	6.00	6,854
1929	103,532.13	91,396	63,184	40,348	6.33	6,374
1930	153,133.22	134,218	92,787	60,346	6.67	9,047
1931	117,783.64	102,494	70,856	46,928	7.01	6,694
1932	81,934.64	70,797	48,943	32,992	7.34	4,495
1933	72,884.31	62,519	43,220	29,664	7.68	3,862
1934	59,056.97	50,286	34,764	24,293	8.02	3,029
1935	12,639.18	10,683	7,385	5,254	8.36	628
1936	4,904.57	4,114	2,844	2,061	8.70	237
1937	41,346.31	34,425	23,799	17,547	9.04	1,941
1938	35,217.12	29,093	20,112	15,105	9.39	1,609
1939	35,480.84	29,088	20,109	15,372	9.73	1,580
1940	7,007.35	5,699	3,940	3,067	10.08	304
1941	145,626.69	117,499	81,229	64,398	10.43	6,174
1944	34,904.27	27,477	18,995	15,909	11.49	1,385
1945	58,220.91	45,455	31,424	26,797	11.84	2,263
1946	53,634.27	41,517	28,701	24,933	12.20	2,044
1947	75,929.90	58,255	40,273	35,657	12.57	2,837
1948	551,251.55	419,260	289,841	261,411	12.93	20,217
1949	1,407,377.84	1,060,741	733,308	674,070	13.30	50,682
1950	1,049,419.57	783,759	541,826	507,594	13.67	37,132
1951	1,294,334.74	957,808	662,149	632,186	14.04	45,027
1952	424,120.80	310,864	214,905	209,216	14.42	14,509
1953	610,359.49	443,188	306,383	303,976	14.79	20,553
1954	83,204.40	59,815	41,351	41,853	15.18	2,757
1955	814,762.40	579,989	400,956	413,806	15.56	26,594
1956	1,892,145.67	1,333,263	921,707	970,439	15.95	60,843
1957	1,509,592.39	1,052,805	727,822	781,770	16.34	47,844
1958	530,016.96	365,712	252,823	277,194	16.74	16,559
1959	1,068,349.77	729,245	504,139	564,211	17.14	32,918
1960	1,006,550.21	679,613	469,828	536,722	17.54	30,600
1961	1,680,495.26	1,121,882	775,576	904,919	17.95	50,413
1962	1,472,553.54	971,885	671,880	800,674	18.36	43,610
1963	1,442,522.24	941,116	650,609	791,913	18.77	42,190
1964	5,680,459.82	3,661,795	2,531,460	3,149,000	19.19	164,096
1965	1,983,331.02	1,262,727	872,944	1,110,387	19.62	56,595
1966	3,067,888.05	1,929,364	1,333,802	1,734,086	20.04	86,531

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 54-S0.5						
NET SALVAGE PERCENT.. 0						
1967	3,485,885.85	2,163,829	1,495,891	1,989,995	20.48	97,168
1968	3,175,971.48	1,945,568	1,345,004	1,830,967	20.92	87,522
1969	4,783,199.92	2,891,157	1,998,705	2,784,495	21.36	130,360
1970	4,923,417.12	2,934,898	2,028,944	2,894,473	21.81	132,713
1971	5,771,537.41	3,392,394	2,345,219	3,426,318	22.26	153,923
1972	5,780,439.69	3,348,377	2,314,789	3,465,651	22.72	152,537
1973	6,825,367.89	3,895,510	2,693,031	4,132,337	23.18	178,272
1974	7,866,693.68	4,419,902	3,055,552	4,811,142	23.66	203,345
1975	4,831,004.96	2,672,270	1,847,385	2,983,620	24.13	123,648
1976	6,231,737.55	3,391,685	2,344,728	3,887,010	24.61	157,944
1977	6,743,054.78	3,608,815	2,494,834	4,248,221	25.10	169,252
1978	7,154,023.77	3,762,516	2,601,090	4,552,934	25.60	177,849
1979	8,466,294.85	4,374,281	3,024,013	5,442,282	26.10	208,517
1980	7,688,667.15	3,899,846	2,696,029	4,992,638	26.61	187,623
1981	8,874,270.45	4,415,748	3,052,680	5,821,590	27.13	214,581
1982	7,489,399.63	3,654,527	2,526,436	4,962,964	27.65	179,492
1983	11,267,423.88	5,387,519	3,724,482	7,542,942	28.18	267,670
1984	11,521,478.30	5,393,780	3,728,810	7,792,668	28.72	271,332
1985	13,251,888.45	6,071,353	4,197,228	9,054,660	29.26	309,455
1986	14,132,821.08	6,328,395	4,374,925	9,757,896	29.82	327,227
1987	16,980,092.42	7,427,262	5,134,590	11,845,502	30.38	389,911
1988	21,488,009.57	9,172,157	6,340,865	15,147,145	30.95	489,407
1989	23,445,227.24	9,751,573	6,741,425	16,703,802	31.54	529,607
1990	27,152,058.52	11,001,743	7,605,689	19,546,370	32.12	608,542
1991	16,162,070.82	6,368,987	4,402,987	11,759,084	32.72	359,385
1992	15,578,443.39	5,963,117	4,122,402	11,456,041	33.33	343,716
1993	19,904,195.26	7,390,428	5,109,126	14,795,069	33.95	435,790
1994	10,963,589.03	3,942,836	2,725,748	8,237,841	34.58	238,226
1995	9,652,308.78	3,356,880	2,320,667	7,331,642	35.22	208,167
1996	17,191,458.27	5,771,860	3,990,183	13,201,275	35.87	368,031
1997	15,647,502.28	5,062,280	3,499,639	12,147,863	36.53	332,545
1998	12,377,707.93	3,850,829	2,662,142	9,715,566	37.20	261,171
1999	9,901,062.02	2,953,784	2,042,000	7,859,062	37.89	207,418
2000	7,933,010.46	2,265,350	1,566,074	6,366,936	38.58	165,032
2001	39,032,357.98	10,632,805	7,350,636	31,681,722	39.29	806,356
2002	24,954,978.48	6,465,086	4,469,422	20,485,556	40.01	512,011
2003	24,652,661.91	6,053,708	4,185,029	20,467,633	40.74	502,396
2004	7,028,614.40	1,628,319	1,125,684	5,902,930	41.49	142,274
2005	52,778,211.63	11,484,011	7,939,089	44,839,123	42.25	1,061,281
2006	43,579,353.09	8,860,990	6,125,750	37,453,603	43.02	870,609
2007	55,751,776.92	10,520,360	7,272,901	48,478,876	43.81	1,106,571

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 54-S0.5						
NET SALVAGE PERCENT.. 0						
2008	45,894,603.55	7,980,613	5,517,131	40,377,473	44.61	905,122
2009	57,233,689.91	9,082,987	6,279,221	50,954,469	45.43	1,121,604
2010	35,834,431.42	5,136,149	3,550,705	32,283,726	46.26	697,876
2011	53,643,285.82	6,844,347	4,731,611	48,911,675	47.11	1,038,244
2012	36,788,751.57	4,108,200	2,840,067	33,948,685	47.97	707,707
2013	45,310,770.63	4,321,288	2,987,379	42,323,392	48.85	866,395
2014	46,052,749.89	3,633,101	2,511,623	43,541,127	49.74	875,374
2015	56,647,878.81	3,503,671	2,422,147	54,225,732	50.66	1,070,386
2016	72,703,312.67	3,244,749	2,243,149	70,460,164	51.59	1,365,772
2017	64,416,378.47	1,741,819	1,204,149	63,212,229	52.54	1,203,126
2018	76,990,891.72	698,307	482,751	76,508,141	53.51	1,429,791
	1,243,010,861.47	288,122,577	199,183,945	1,043,826,917		25,882,981
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					40.3	2.08

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 368 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 47-R1.5						
NET SALVAGE PERCENT.. 0						
1913	0.81	1	1			
1914	0.89	1	1			
1917	0.67	1	1			
1922	0.89	1	1			
1923	1.89	2	2			
1924	3.78	4	4			
1925	1.03	1	1			
1926	0.81	1	1			
1927	2.53	2	2	1	0.98	1
1928	1.95	2	2			
1929	10.71	10	10	1	1.65	1
1930	6.10	6	6			
1931	18.66	18	19			
1932	11.20	11	11			
1933	21.45	20	21			
1934	52.57	49	51	2	3.21	1
1935	22.30	21	22			
1936	258.79	239	249	10	3.68	3
1937	1,539.65	1,412	1,471	69	3.91	18
1938	1,593.91	1,454	1,515	79	4.13	19
1939	2,199.47	1,995	2,078	121	4.36	28
1940	2,444.62	2,206	2,298	147	4.59	32
1941	9,318.09	8,360	8,709	609	4.83	126
1942	3,330.04	2,971	3,095	235	5.07	46
1943	472.17	419	437	35	5.33	7
1944	2,488.07	2,193	2,285	203	5.58	36
1945	4,510.41	3,949	4,114	396	5.85	68
1946	34,373.77	29,898	31,147	3,227	6.12	527
1947	66,545.54	57,498	59,900	6,646	6.39	1,040
1948	89,680.13	76,954	80,169	9,511	6.67	1,426
1949	124,755.46	106,308	110,750	14,005	6.95	2,015
1950	151,076.49	127,805	133,145	17,931	7.24	2,477
1951	229,314.15	192,576	200,622	28,692	7.53	3,810
1952	329,686.66	274,761	286,241	43,446	7.83	5,549
1953	403,605.40	333,790	347,736	55,869	8.13	6,872
1954	592,462.59	486,074	506,383	86,080	8.44	10,199
1955	752,102.86	612,084	637,658	114,445	8.75	13,079
1956	903,185.05	728,888	759,342	143,843	9.07	15,859
1957	700,157.01	560,126	583,529	116,628	9.40	12,407
1958	637,029.93	505,152	526,258	110,772	9.73	11,385
1959	719,322.68	565,201	588,816	130,507	10.07	12,960

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 368 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 47-R1.5						
NET SALVAGE PERCENT.. 0						
1960	935,778.00	728,316	758,746	177,032	10.42	16,990
1961	745,060.39	574,330	598,326	146,734	10.77	13,624
1962	704,008.46	537,144	559,587	144,421	11.14	12,964
1963	1,032,136.24	779,376	811,939	220,197	11.51	19,131
1964	813,059.34	607,201	632,571	180,488	11.90	15,167
1965	889,348.54	656,793	684,235	205,114	12.29	16,690
1966	1,536,368.53	1,121,549	1,168,409	367,960	12.69	28,996
1967	3,001,688.45	2,164,397	2,254,829	746,859	13.11	56,969
1968	6,251,967.41	4,452,214	4,638,234	1,613,733	13.53	119,271
1969	9,197,815.81	6,463,949	6,734,022	2,463,794	13.97	176,363
1970	6,200,971.19	4,298,451	4,478,046	1,722,925	14.42	119,482
1971	3,499,950.67	2,391,866	2,491,802	1,008,149	14.88	67,752
1972	3,725,618.35	2,509,651	2,614,508	1,111,110	15.34	72,432
1973	5,827,613.92	3,864,815	4,026,293	1,801,321	15.83	113,792
1974	5,674,597.11	3,704,207	3,858,974	1,815,623	16.32	111,251
1975	2,395,323.49	1,538,109	1,602,373	792,950	16.82	47,143
1976	1,601,117.08	1,010,401	1,052,617	548,500	17.34	31,632
1977	2,894,607.18	1,794,656	1,869,639	1,024,968	17.86	57,389
1978	4,586,772.10	2,791,097	2,907,713	1,679,059	18.40	91,253
1979	4,056,825.14	2,422,006	2,523,201	1,533,624	18.94	80,973
1980	3,659,080.33	2,140,964	2,230,417	1,428,663	19.50	73,265
1981	4,214,731.71	2,414,957	2,515,857	1,698,875	20.07	84,647
1982	5,070,109.37	2,842,506	2,961,270	2,108,839	20.65	102,123
1983	4,608,569.60	2,525,911	2,631,447	1,977,123	21.24	93,085
1984	7,454,453.15	3,992,083	4,158,878	3,295,575	21.83	150,965
1985	10,641,305.81	5,560,614	5,792,944	4,848,362	22.44	216,059
1986	11,151,695.25	5,680,227	5,917,555	5,234,140	23.06	226,979
1987	11,599,705.56	5,752,990	5,993,358	5,606,348	23.69	236,655
1988	13,331,506.22	6,433,118	6,701,903	6,629,603	24.32	272,599
1989	18,444,925.74	8,645,506	9,006,728	9,438,198	24.97	377,981
1990	15,537,559.47	7,067,880	7,363,186	8,174,373	25.62	319,062
1991	9,177,336.08	4,045,829	4,214,870	4,962,466	26.28	188,831
1992	9,348,396.09	3,985,969	4,152,509	5,195,887	26.96	192,726
1993	9,430,977.13	3,886,789	4,049,185	5,381,792	27.63	194,781
1994	12,044,164.67	4,786,953	4,986,959	7,057,206	28.32	249,195
1995	13,672,787.10	5,233,533	5,452,198	8,220,589	29.01	283,371
1996	7,478,198.43	2,751,005	2,865,946	4,612,252	29.71	155,242
1997	12,456,644.45	4,394,330	4,577,931	7,878,713	30.42	258,998
1998	11,229,330.31	3,789,338	3,947,662	7,281,668	31.14	233,836
1999	9,853,451.80	3,174,092	3,306,710	6,546,742	31.86	205,485
2001	25,754,518.71	7,496,110	7,809,308	17,945,211	33.32	538,572

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 368 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 47-R1.5						
NET SALVAGE PERCENT.. 0						
2002	11,412,850.59	3,142,186	3,273,471	8,139,380	34.06	238,972
2003	4,084,324.52	1,060,168	1,104,463	2,979,862	34.80	85,628
2004	10,818,705.12	2,635,653	2,745,774	8,072,931	35.55	227,087
2005	15,535,551.45	3,533,561	3,681,198	11,854,353	36.31	326,476
2006	11,129,661.50	2,351,475	2,449,723	8,679,938	37.07	234,150
2007	15,141,638.37	2,950,954	3,074,249	12,067,389	37.84	318,906
2008	15,929,013.57	2,843,488	2,962,293	12,966,721	38.61	335,838
2009	12,741,152.45	2,065,723	2,152,032	10,589,120	39.38	268,896
2010	18,381,680.51	2,675,086	2,786,855	15,594,826	40.16	388,317
2011	20,612,598.15	2,653,254	2,764,111	17,848,487	40.95	435,860
2012	19,694,712.34	2,204,035	2,296,123	17,398,589	41.74	416,833
2013	18,618,129.96	1,766,674	1,840,488	16,777,642	42.54	394,397
2014	28,198,666.13	2,195,830	2,287,575	25,911,091	43.34	597,856
2015	21,219,350.29	1,291,197	1,345,145	19,874,205	44.14	450,254
2016	25,509,756.24	1,112,736	1,159,228	24,350,528	44.95	541,725
2017	20,675,591.36	541,080	563,688	20,111,903	45.77	439,412
2018	35,733,270.34	311,594	324,613	35,408,658	46.59	760,006
	602,928,338.45	181,028,390	188,592,017	414,336,322		12,484,325

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 33.2 2.07

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 369.1 SERVICES - AERIAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R4						
NET SALVAGE PERCENT.. 0						
1952	55,515.45	52,080	54,471	1,044	3.28	318
1953	17,932.88	16,732	17,500	433	3.55	122
1954	3,550.02	3,294	3,445	105	3.82	27
1955	275,831.94	254,546	266,233	9,599	4.09	2,347
1956	417,410.73	382,995	400,579	16,832	4.37	3,852
1957	386,637.18	352,644	368,834	17,803	4.66	3,820
1958	431,683.86	391,287	409,251	22,433	4.96	4,523
1959	431,276.58	388,395	406,227	25,050	5.27	4,753
1960	376,090.76	336,424	351,870	24,221	5.59	4,333
1961	425,856.71	378,127	395,487	30,370	5.94	5,113
1962	481,750.33	424,485	443,974	37,776	6.30	5,996
1963	585,779.04	511,947	535,451	50,328	6.68	7,534
1964	680,776.52	589,709	616,783	63,994	7.09	9,026
1965	471,491.66	404,502	423,073	48,419	7.53	6,430
1966	676,417.51	574,448	600,822	75,596	7.99	9,461
1967	647,680.61	543,929	568,901	78,780	8.49	9,279
1968	716,030.18	594,169	621,448	94,582	9.02	10,486
1969	990,151.90	811,360	848,611	141,541	9.57	14,790
1970	928,668.04	750,642	785,105	143,563	10.16	14,130
1971	753,326.06	600,243	627,801	125,525	10.77	11,655
1972	843,945.06	662,261	692,666	151,279	11.41	13,258
1973	986,782.37	762,053	797,040	189,742	12.07	15,720
1974	1,111,716.99	844,482	883,253	228,464	12.74	17,933
1975	1,084,287.07	809,735	846,911	237,376	13.42	17,688
1976	1,066,062.57	782,042	817,947	248,116	14.12	17,572
1977	1,213,481.22	873,937	914,061	299,420	14.83	20,190
1978	1,230,257.93	869,079	908,980	321,278	15.56	20,648
1979	1,232,053.25	853,135	892,304	339,749	16.30	20,843
1980	1,459,764.17	990,158	1,035,617	424,147	17.05	24,877
1981	965,870.91	641,116	670,550	295,321	17.82	16,572
1982	1,333,266.73	865,370	905,100	428,167	18.60	23,020
1983	1,303,114.69	826,370	864,310	438,805	19.39	22,630
1984	1,590,199.29	984,127	1,029,310	560,889	20.20	27,767
1985	1,493,934.34	901,156	942,529	551,405	21.03	26,220
1986	1,739,654.58	1,022,134	1,069,061	670,594	21.86	30,677
1987	1,873,519.89	1,070,735	1,119,894	753,626	22.71	33,185
1988	1,975,838.08	1,097,143	1,147,514	828,324	23.57	35,143
1989	2,290,969.34	1,234,099	1,290,758	1,000,211	24.45	40,908
1990	1,895,157.57	989,424	1,034,850	860,308	25.33	33,964
1991	1,480,284.65	747,677	782,004	698,281	26.23	26,621
1992	1,492,337.33	728,141	761,571	730,766	27.14	26,926

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 369.1 SERVICES - AERIAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R4						
NET SALVAGE PERCENT.. 0						
1993	1,661,434.35	782,120	818,028	843,406	28.05	30,068
1994	1,532,509.12	694,548	726,436	806,073	28.98	27,815
1995	3,095,073.18	1,348,400	1,410,307	1,684,766	29.91	56,328
1996	1,390,888.82	581,280	607,967	782,922	30.85	25,378
1997	3,152,871.71	1,261,149	1,319,050	1,833,822	31.80	57,667
1998	2,688,502.21	1,026,712	1,073,850	1,614,652	32.76	49,287
1999	3,001,898.79	1,092,001	1,142,136	1,859,763	33.72	55,153
2000	2,083,228.07	720,089	753,149	1,330,079	34.68	38,353
2001	8,453,527.46	2,767,347	2,894,399	5,559,128	35.65	155,936
2002	7,558,370.63	2,334,554	2,441,736	5,116,635	36.63	139,684
2003	4,192,336.85	1,218,167	1,274,095	2,918,242	37.60	77,613
2004	5,601,979.43	1,524,187	1,594,164	4,007,815	38.58	103,883
2005	5,943,428.70	1,506,065	1,575,210	4,368,219	39.57	110,392
2006	5,282,703.74	1,239,956	1,296,884	3,985,820	40.56	98,270
2007	4,111,303.27	888,987	929,802	3,181,501	41.54	76,589
2008	4,814,179.40	950,126	993,748	3,820,431	42.54	89,808
2009	4,786,951.56	855,333	894,602	3,892,350	43.53	89,418
2010	4,363,160.52	698,106	730,157	3,633,004	44.52	81,604
2011	3,950,165.14	557,487	583,082	3,367,083	45.52	73,969
2012	3,739,252.36	457,871	478,892	3,260,360	46.51	70,100
2013	3,844,066.63	398,168	416,449	3,427,618	47.51	72,145
2014	4,550,652.99	385,531	403,231	4,147,422	48.51	85,496
2015	4,304,813.12	284,290	297,342	4,007,471	49.50	80,959
2016	6,204,889.31	292,685	306,123	5,898,766	50.50	116,807
2017	6,200,219.72	175,466	183,522	6,016,698	51.50	116,829
2018	7,984,927.93	75,298	78,755	7,906,173	52.50	150,594
	153,909,691.00	51,032,255	53,375,212	100,534,479		2,770,502

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.3 1.80

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 369.2 SERVICES - UNDERGROUND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
1940	7,270.26	6,801	6,792	478	3.55	135
1941	11,949.85	11,124	11,109	841	3.80	221
1942	5,462.31	5,059	5,052	410	4.06	101
1943	1,289.29	1,188	1,186	103	4.32	24
1944	4,466.33	4,094	4,089	377	4.58	82
1945	5,546.68	5,060	5,053	494	4.83	102
1946	18,509.47	16,793	16,770	1,739	5.10	341
1947	21,784.45	19,662	19,636	2,148	5.36	401
1948	31,341.86	28,139	28,101	3,241	5.62	577
1949	44,640.79	39,852	39,799	4,842	5.90	821
1952	45,494.52	39,911	39,857	5,638	6.75	835
1953	111,476.11	97,167	97,037	14,439	7.06	2,045
1954	97,379.57	84,331	84,218	13,162	7.37	1,786
1955	69,406.10	59,689	59,609	9,797	7.70	1,272
1956	95,016.76	81,127	81,018	13,999	8.04	1,741
1957	81,869.71	69,366	69,273	12,597	8.40	1,500
1958	70,182.84	58,992	58,913	11,270	8.77	1,285
1959	102,179.22	85,161	85,047	17,132	9.16	1,870
1960	178,051.21	147,102	146,905	31,146	9.56	3,258
1961	194,696.66	159,369	159,155	35,542	9.98	3,561
1962	169,121.39	137,112	136,928	32,193	10.41	3,093
1963	111,947.08	89,843	89,723	22,224	10.86	2,046
1964	156,732.55	124,446	124,279	32,454	11.33	2,864
1965	244,122.87	191,658	191,401	52,722	11.82	4,460
1966	256,072.64	198,666	198,400	57,673	12.33	4,677
1967	213,475.94	163,599	163,380	50,096	12.85	3,899
1968	281,370.51	212,871	212,586	68,785	13.39	5,137
1969	277,052.46	206,834	206,557	70,495	13.94	5,057
1970	306,747.86	225,822	225,519	81,229	14.51	5,598
1971	452,660.06	328,382	327,942	124,718	15.10	8,259
1972	636,184.14	454,465	453,855	182,329	15.71	11,606
1973	1,593,663.67	1,120,776	1,119,273	474,391	16.32	29,068
1974	1,486,275.66	1,027,968	1,026,589	459,687	16.96	27,104
1975	1,405,929.20	955,779	954,497	451,432	17.61	25,635
1976	2,065,178.00	1,379,167	1,377,317	687,861	18.27	37,650
1977	2,529,150.79	1,658,212	1,655,988	873,163	18.94	46,102
1978	4,260,180.27	2,739,679	2,736,005	1,524,175	19.63	77,645
1979	4,468,968.45	2,817,059	2,813,281	1,655,687	20.33	81,441
1980	4,993,134.13	3,083,011	3,078,876	1,914,258	21.04	90,982
1981	4,947,072.18	2,988,922	2,984,913	1,962,159	21.77	90,131
1982	2,974,564.66	1,757,700	1,755,343	1,219,222	22.50	54,188

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 369.2 SERVICES - UNDERGROUND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
1983	5,741,533.93	3,314,415	3,309,970	2,431,564	23.25	104,583
1984	7,552,791.46	4,255,620	4,249,913	3,302,878	24.01	137,563
1985	7,932,148.49	4,359,826	4,353,979	3,578,169	24.77	144,456
1986	9,720,879.54	5,205,045	5,198,064	4,522,816	25.55	177,018
1987	11,247,767.07	5,861,099	5,853,238	5,394,529	26.34	204,804
1988	11,357,302.43	5,753,042	5,745,326	5,611,976	27.14	206,779
1989	10,680,431.65	5,254,772	5,247,725	5,432,707	27.94	194,442
1990	10,382,482.38	4,953,379	4,946,736	5,435,746	28.76	189,004
1991	7,574,496.00	3,499,417	3,494,724	4,079,772	29.59	137,877
1992	8,429,712.30	3,767,323	3,762,271	4,667,441	30.42	153,433
1993	10,189,918.05	4,398,376	4,392,477	5,797,441	31.26	185,459
1994	5,399,463.34	2,247,149	2,244,135	3,155,328	32.11	98,266
1995	9,644,064.51	3,862,930	3,857,749	5,786,316	32.97	175,502
1996	3,956,883.56	1,522,332	1,520,290	2,436,594	33.84	72,003
1997	9,490,920.43	3,499,587	3,494,894	5,996,026	34.72	172,697
1998	5,671,820.00	2,000,621	1,997,938	3,673,882	35.60	103,199
1999	9,396,592.44	3,162,423	3,158,182	6,238,410	36.49	170,962
2000	1,215,912.77	389,311	388,789	827,124	37.39	22,122
2001	11,329,845.43	3,440,194	3,435,580	7,894,265	38.30	206,117
2002	11,354,606.93	3,259,794	3,255,422	8,099,185	39.21	206,559
2003	8,141,312.26	2,201,085	2,198,133	5,943,179	40.13	148,098
2004	1,419,422.92	359,753	359,271	1,060,152	41.06	25,820
2005	11,641,314.19	2,753,753	2,750,060	8,891,254	41.99	211,747
2006	6,514,554.40	1,429,619	1,427,702	5,086,852	42.93	118,492
2007	4,968,914.10	1,005,509	1,004,160	3,964,754	43.87	90,375
2008	4,828,591.01	894,593	893,393	3,935,198	44.81	87,820
2009	3,797,463.09	637,290	636,435	3,161,028	45.77	69,063
2010	1,818,813.95	273,822	273,455	1,545,359	46.72	33,077
2011	6,135,889.97	815,521	814,427	5,321,463	47.69	111,584
2012	1,118,029.31	129,076	128,903	989,126	48.65	20,331
2013	1,432,832.68	140,160	139,972	1,292,861	49.62	26,055
2014	1,735,433.76	139,147	138,960	1,596,474	50.59	31,557
2015	1,501,431.56	93,629	93,504	1,407,928	51.57	27,301
2016	2,823,347.75	126,288	126,119	2,697,229	52.54	51,337
2017	1,852,084.57	49,840	49,773	1,802,312	53.52	33,675
2018	2,054,521.11	18,306	18,281	2,036,240	54.51	37,355
	265,081,147.84	107,956,004	107,811,221	157,269,927		4,825,132

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.6 1.82

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 370.1 METER TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
2013	239,279.78	33,293	44,603	194,677	30.13	6,461
2014	482,213.62	55,247	74,015	408,199	30.99	13,172
2015	1,038,877.16	92,907	124,468	914,409	31.87	28,692
2016	244,754.76	15,664	20,985	223,770	32.76	6,831
2017	384,669.90	14,837	19,877	364,793	33.65	10,841
2018	393,425.87	5,059	6,778	386,648	34.55	11,191
	2,783,221.09	217,007	290,726	2,492,495		77,188

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.3 2.77

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 370.2 SMART METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
SURVIVOR CURVE.. IOWA 15-S2						
NET SALVAGE PERCENT.. 0						
2011	2,374,013.19	1,104,700	1,144,960	1,229,053	8.02	153,249
2012	22,107,833.95	9,108,428	9,440,376	12,667,458	8.82	1,436,220
2013	123,025,676.48	43,714,714	45,307,854	77,717,822	9.67	8,037,003
2014	93,389,991.25	27,519,229	28,522,140	64,867,851	10.58	6,131,177
2015	39,262,781.58	9,082,659	9,413,667	29,849,115	11.53	2,588,822
2016	10,220,680.82	1,696,633	1,758,465	8,462,216	12.51	676,436
2017	9,889,531.07	988,953	1,024,995	8,864,536	13.50	656,632
2018	5,005,082.66	166,819	172,898	4,832,184	14.50	333,254
	305,275,591.00	93,382,135	96,785,355	208,490,236		20,012,793

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.4 6.56

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 36-R4						
NET SALVAGE PERCENT.. 0						
1994	19,065.30	12,255	19,065			
1995	36,305.98	22,520	36,306			
1996	24,135.77	14,421	24,136			
1997	51,638.40	29,635	49,750	1,888	15.34	123
1998	742,575.59	408,417	685,630	56,946	16.20	3,515
1999	156,401.81	82,199	137,991	18,410	17.08	1,078
	1,030,122.85	569,447	952,878	77,245		4,716

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.4 0.46

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 24-L0						
NET SALVAGE PERCENT.. 0						
1914	0.46					
1915	0.36					
1916	0.80	1	1			
1917	0.56	1	1			
1918	0.95	1	1			
1919	0.89	1	1			
1959	13,872.88	10,387	13,873			
1960	17,271.20	12,817	17,271			
1961	13,447.73	9,884	13,448			
1962	17,297.13	12,591	17,297			
1963	13,836.76	9,974	13,837			
1964	5,315.75	3,794	5,316			
1965	15,879.46	11,215	15,879			
1966	23,274.05	16,273	23,274			
1967	20,396.65	14,099	20,397			
1968	23,864.68	16,317	23,865			
1969	28,003.64	18,926	28,004			
1970	39,730.12	26,537	39,437	293	7.97	37
1971	102,934.94	67,937	100,962	1,973	8.16	242
1972	172,933.84	112,767	167,584	5,350	8.35	641
1973	181,367.69	116,755	173,510	7,858	8.55	919
1974	182,796.45	116,076	172,501	10,295	8.76	1,175
1975	178,916.53	112,122	166,625	12,292	8.96	1,372
1976	277,231.25	171,307	254,580	22,651	9.17	2,470
1977	328,556.67	200,147	297,440	31,117	9.38	3,317
1978	286,530.67	171,918	255,488	31,043	9.60	3,234
1979	346,540.85	204,747	304,276	42,265	9.82	4,304
1980	247,942.75	144,221	214,328	33,615	10.04	3,348
1981	274,272.90	156,906	233,179	41,094	10.27	4,001
1982	408,084.79	229,548	341,133	66,952	10.50	6,376
1983	596,419.12	329,522	489,705	106,714	10.74	9,936
1984	622,761.53	338,110	502,467	120,295	10.97	10,966
1985	768,085.30	409,005	607,825	160,260	11.22	14,283
1986	272,212.86	142,117	211,201	61,012	11.47	5,319
1987	412,847.40	211,242	313,928	98,919	11.72	8,440
1988	689,487.83	345,316	513,176	176,312	11.98	14,717
1989	472,776.41	231,660	344,271	128,505	12.24	10,499
1990	666,789.34	319,225	474,402	192,387	12.51	15,379
1991	488,018.37	228,149	339,054	148,964	12.78	11,656
1992	421,051.71	191,928	285,225	135,827	13.06	10,400
1993	453,873.02	201,406	299,311	154,562	13.35	11,578

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 24-L0						
NET SALVAGE PERCENT.. 0						
1994	453,662.97	195,833	291,029	162,634	13.64	11,923
1995	1,851,242.15	776,744	1,154,324	696,918	13.93	50,030
1996	1,924,392.15	782,593	1,163,016	761,376	14.24	53,467
1997	4,135,096.61	1,629,931	2,422,250	1,712,847	14.54	117,802
1998	12,275,249.11	4,674,783	6,947,223	5,328,026	14.86	358,548
1999	9,108,058.84	3,347,212	4,974,312	4,133,747	15.18	272,315
2000	87,636.16	31,001	46,071	41,565	15.51	2,680
2001	2,081,351.77	707,660	1,051,658	1,029,694	15.84	65,006
2002	500,989.68	163,237	242,588	258,402	16.18	15,970
2003	1,530,053.12	476,229	707,727	822,326	16.53	49,747
2004	605,521.16	179,386	266,587	338,934	16.89	20,067
2005	341,437.85	96,029	142,709	198,729	17.25	11,521
2006	187,990.05	49,973	74,265	113,725	17.62	6,454
2007	147,326.55	36,832	54,736	92,591	18.00	5,144
2008	352,958.54	82,504	122,610	230,349	18.39	12,526
2009	369,750.24	80,114	119,058	250,692	18.80	13,335
2010	662,850.75	132,292	196,600	466,251	19.21	24,271
2011	627,994.27	113,824	169,154	458,840	19.65	23,351
2012	903,431.77	146,808	218,172	685,260	20.10	34,093
2013	662,246.96	94,370	140,244	522,003	20.58	25,365
2014	726,497.61	88,088	130,908	595,590	21.09	28,240
2015	915,741.38	90,429	134,387	781,354	21.63	36,124
2016	1,173,775.53	87,540	130,094	1,043,682	22.21	46,992
2017	6,999,115.92	332,458	494,068	6,505,048	22.86	284,560
2018	2,160,602.87	37,811	56,191	2,104,412	23.58	89,246
	59,869,600.30	19,348,630	28,744,054	31,125,546		1,813,386

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.2 3.03

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
NET SALVAGE PERCENT.. 0						
1927	5,751.36	5,751	5,751			
1929	14,004.80	13,936	10,792	3,213	0.22	3,213
1931	1,075.45	1,053	815	260	0.92	260
1935	50.25	48	37	13	2.39	5
1941	129.90	117	91	39	4.64	8
1946	19,578.90	16,729	12,955	6,624	6.55	1,011
1948	215.87	181	140	76	7.32	10
1949	13,572.45	11,247	8,710	4,862	7.71	631
1950	5,950.18	4,879	3,778	2,172	8.10	268
1951	1,377.12	1,117	865	512	8.50	60
1952	981.95	788	610	372	8.89	42
1954	959.98	753	583	377	9.68	39
1955	1,783,044.53	1,383,643	1,071,497	711,548	10.08	70,590
1956	10,888.67	8,350	6,466	4,423	10.49	422
1957	1,158.59	878	680	479	10.89	44
1958	508,021.10	380,452	294,623	213,398	11.30	18,885
1959	18,148.40	13,430	10,400	7,748	11.70	662
1960	6,328.45	4,625	3,582	2,746	12.11	227
1961	10,696.14	7,718	5,977	4,719	12.53	377
1962	1,494.46	1,065	825	669	12.94	52
1963	25,555.62	17,968	13,914	11,642	13.36	871
1964	35,896.35	24,904	19,286	16,610	13.78	1,205
1966	7,150.71	4,828	3,739	3,412	14.62	233
1967	2,284.74	1,521	1,178	1,107	15.05	74
1968	11,514.21	7,553	5,849	5,665	15.48	366
1969	2,925,315.52	1,891,041	1,464,428	1,460,888	15.91	91,822
1970	3,533.50	2,250	1,742	1,792	16.35	110
1971	27,057.89	16,968	13,140	13,918	16.78	829
1972	6,218.08	3,839	2,973	3,245	17.22	188
1973	8,156.69	4,954	3,836	4,321	17.67	245
1974	1,109,998.60	663,035	513,456	596,543	18.12	32,922
1975	3,532.85	2,075	1,607	1,926	18.57	104
1976	1,405.70	812	629	777	19.02	41
1978	12,528.42	6,977	5,403	7,125	19.94	357
1979	49,431.66	27,023	20,927	28,505	20.40	1,397
1980	514,893.54	276,096	213,810	301,084	20.87	14,427
1981	120,378.95	63,266	48,993	71,386	21.35	3,344
1982	376,512.59	193,945	150,192	226,321	21.82	10,372
1983	124,422.17	62,764	48,605	75,817	22.30	3,400
1984	385,390.58	190,213	147,302	238,089	22.79	10,447
1985	604,008.13	291,537	225,767	378,241	23.28	16,247

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
NET SALVAGE PERCENT.. 0						
1986	1,483,870.82	699,734	541,876	941,995	23.78	39,613
1987	295,387.48	136,008	105,325	190,062	24.28	7,828
1988	726,378.66	326,384	252,753	473,626	24.78	19,113
1989	572,534.38	250,644	194,099	378,435	25.30	14,958
1990	342,603.06	146,100	113,140	229,463	25.81	8,890
1991	1,028.95	427	331	698	26.34	26
1992	2,758,129.60	1,111,223	860,534	1,897,596	26.87	70,621
1993	2,308,233.21	902,773	699,110	1,609,123	27.40	58,727
1994	236,579.53	89,638	69,416	167,164	27.95	5,981
1995	160,864.09	58,984	45,677	115,187	28.50	4,042
1996	37,470.65	13,281	10,285	27,186	29.05	936
1997	533,722.47	182,416	141,264	392,458	29.62	13,250
1998	5,149,515.88	1,694,757	1,312,425	3,837,091	30.19	127,098
1999	499,294.52	157,777	122,183	377,112	30.78	12,252
2001	672,471.52	194,721	150,793	521,679	31.97	16,318
2002	172,481.25	47,605	36,865	135,616	32.58	4,163
2003	3,789,268.44	993,622	769,464	3,019,804	33.20	90,958
2004	100,945.76	25,035	19,387	81,559	33.84	2,410
2005	411,487.24	96,197	74,495	336,992	34.48	9,774
2006	229,769.87	50,345	38,987	190,783	35.14	5,429
2007	386,939.74	79,021	61,194	325,746	35.81	9,097
2008	187,650.44	35,445	27,449	160,201	36.50	4,389
2009	585,768.72	101,531	78,626	507,143	37.20	13,633
2010	6,218,145.60	978,301	757,599	5,460,547	37.92	144,002
2011	2,774,724.43	390,931	302,738	2,471,986	38.66	63,942
2012	2,710,848.28	336,145	260,312	2,450,536	39.42	62,165
2013	553,357.27	59,148	45,804	507,553	40.19	12,629
2014	1,935,577.56	172,053	133,239	1,802,339	41.00	43,959
2015	2,336,653.68	164,594	127,462	2,209,192	41.83	52,814
2016	935,715.42	48,245	37,361	898,354	42.68	21,049
2017	1,406,366.80	44,385	34,372	1,371,995	43.58	31,482
2018	121,186.63	1,320	1,022	120,165	44.51	2,700
	49,393,587.00	15,199,119	11,771,540	37,622,047		1,260,055

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.9 2.55

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - OFFICE MACHINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2011	83,461.00	62,596	56,913	26,548	2.50	10,619
	83,461.00	62,596	56,913	26,548		10,619

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.5 12.72

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - FURNITURE AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	78,405.46	49,657	40,604	37,801	5.50	6,873
2012	1,193.88	517	423	771	8.50	91
2013	11,777.35	4,318	3,531	8,246	9.50	868
2015	252,830.77	58,993	48,237	204,594	11.50	17,791
2016	145,009.33	24,169	19,762	125,247	12.50	10,020
2018	20,348.93	678	554	19,794	14.50	1,365
	509,565.72	138,332	113,111	396,454		37,008

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.7 7.26

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	27,421.38	24,679	27,421			
2015	3,342,407.25	2,339,685	2,654,945	687,462	1.50	458,308
2016	2,950,105.55	1,475,053	1,673,809	1,276,297	2.50	510,519
2017	5,688,246.65	1,706,474	1,936,413	3,751,834	3.50	1,071,953
2018	10,984,416.96	1,098,442	1,246,451	9,737,966	4.50	2,163,992
	22,992,597.79	6,644,333	7,539,039	15,453,559		4,204,772

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.7 18.29

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SMART METER COMPUTER EQUIP.

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	2,246,206.67	2,021,586	1,579,069	667,138	0.50	667,138
2015	579,344.22	405,541	316,769	262,575	1.50	175,050
2018	77,250.00	7,725	6,034	71,216	4.50	15,826
	2,902,800.89	2,434,852	1,901,872	1,000,928		858,014

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.2 29.56

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2008	1,656.92	1,160	460	1,197	4.50	266
2013	44,813.08	16,432	6,522	38,291	9.50	4,031
	46,470.00	17,592	6,982	39,488		4,297
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					9.2	9.25

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	654,752.82	632,930	548,406	106,347	0.50	106,347
2005	1,653,065.02	1,487,759	1,289,077	363,988	1.50	242,659
2006	1,605,606.17	1,338,000	1,159,318	446,288	2.50	178,515
2007	1,052,519.06	806,935	699,174	353,345	3.50	100,956
2008	521,432.98	365,003	316,259	205,174	4.50	45,594
2009	967,257.27	612,593	530,785	436,472	5.50	79,359
2010	1,954,316.24	1,107,452	959,558	994,758	6.50	153,040
2011	2,711,264.82	1,355,632	1,174,595	1,536,670	7.50	204,889
2012	1,690,962.99	732,745	634,891	1,056,072	8.50	124,244
2013	2,621,157.61	961,100	832,751	1,788,407	9.50	188,253
2014	3,347,957.09	1,004,387	870,257	2,477,700	10.50	235,971
2015	3,157,790.51	736,807	638,411	2,519,380	11.50	219,077
2016	4,440,979.77	740,178	641,331	3,799,649	12.50	303,972
2017	4,759,315.83	475,932	412,374	4,346,942	13.50	321,996
2018	3,449,974.82	114,988	99,632	3,350,343	14.50	231,058
	34,588,353.00	12,472,441	10,806,819	23,781,534		2,735,930

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.7 7.91

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 395.1 LABORATORY EQUIPMENT - TESTING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	55,889.29	43,314	45,067	10,822	4.50	2,405
2005	158,343.65	106,882	111,209	47,135	6.50	7,252
2006	6,644.07	4,153	4,321	2,323	7.50	310
2007	90,148.95	51,836	53,934	36,215	8.50	4,261
	311,025.96	206,185	214,531	96,495		14,228
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					6.8	4.57

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 395.2 LABORATORY EQUIPMENT - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	101,381.00	77,726	75,266	26,115	3.50	7,461
	101,381.00	77,726	75,266	26,115		7,461

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.5 7.36

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L3						
NET SALVAGE PERCENT.. 0						
1998	27,839.15	19,599	16,801	11,038	5.92	1,865
2002	1,159,560.47	767,049	657,552	502,008	6.77	74,152
2003	328,676.04	211,832	181,593	147,083	7.11	20,687
2004	374.23	233	200	174	7.54	23
2006	242,095.48	137,147	117,569	124,526	8.67	14,363
2007	951,922.05	506,423	434,131	517,791	9.36	55,320
2009	579,323.51	262,434	224,971	354,353	10.94	32,391
2010	22,907,653.17	9,392,138	8,051,400	14,856,253	11.80	1,259,004
2011	33,776,738.16	12,345,398	10,583,079	23,193,659	12.69	1,827,712
2012	4,096,457.75	1,308,818	1,121,983	2,974,475	13.61	218,551
2013	6,561,834.43	1,784,819	1,530,034	5,031,800	14.56	345,591
2014	22,624,548.76	5,067,899	4,344,450	18,280,099	15.52	1,177,841
2015	6,141,488.85	1,071,690	918,705	5,222,784	16.51	316,341
2016	11,136,615.46	1,392,077	1,193,357	9,943,258	17.50	568,186
2017	3,289,403.26	246,705	211,487	3,077,916	18.50	166,374
2018	11,815,173.23	295,379	253,214	11,561,960	19.50	592,921
	125,639,704.00	34,809,640	29,840,526	95,799,178		6,671,322

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.4 5.31

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 397.1 COMMUNICATION EQUIPMENT - SMART METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-S2						
NET SALVAGE PERCENT.. 0						
2011	23,991,452.04	11,163,942	10,391,166	13,600,286	8.02	1,695,796
2013	2,030,708.07	721,571	671,623	1,359,085	9.67	140,547
2014	746,106.50	219,855	204,637	541,470	10.58	51,179
2015	563,997.38	130,470	121,439	442,558	11.53	38,383
2016	994,352.70	165,063	153,637	840,716	12.51	67,204
2017	6,659,031.61	665,903	619,808	6,039,224	13.50	447,350
2018	494,569.59	16,484	15,343	479,226	14.50	33,050
	35,480,217.89	13,083,288	12,177,653	23,302,564		2,473,509

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.4 6.97

PECO ENERGY COMPANY
ELECTRIC PLANT

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	626,876.02	605,982	571,602	55,274	0.50	55,274
2007	25,817.98	19,794	18,671	7,147	3.50	2,042
	652,694.00	625,776	590,273	62,421		57,316
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					1.1	8.78

COMMON PLANT

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R1						
NET SALVAGE PERCENT.. 0						
1892	662.94	663	663			
1914	1,915.22	1,845	1,915			
1922	232.91	214	233			
1924	5,907.45	5,358	5,907			
1925	5,647.17	5,091	5,647			
1927	13,978.16	12,448	13,840	138	6.02	23
1930	122.02	107	119	3	6.96	
1931	403.82	350	389	15	7.28	2
1933	25.47	22	24	1	7.93	
1937	121.50	101	112	10	9.28	1
1938	8,310.34	6,855	7,622	688	9.63	71
1941	1,241.54	1,000	1,112	130	10.70	12
1942	3,975.39	3,176	3,531	444	11.06	40
1944	452,388.51	355,247	394,975	57,414	11.81	4,861
1946	1,117.60	862	958	160	12.58	13
1947	293.41	224	249	44	12.97	3
1948	238.29	180	200	38	13.37	3
1949	60,980.97	45,714	50,826	10,155	13.77	737
1950	3,326.06	2,469	2,745	581	14.17	41
1951	16,504.21	12,129	13,485	3,019	14.58	207
1952	63,925.13	46,491	51,690	12,235	15.00	816
1953	79,248.67	57,031	63,409	15,840	15.42	1,027
1954	1,992.49	1,418	1,577	415	15.85	26
1955	35,565.89	25,038	27,838	7,728	16.28	475
1956	1,395,306.57	971,133	1,079,736	315,571	16.72	18,874
1957	46,520.58	31,998	35,576	10,945	17.17	637
1958	114,683.49	77,943	86,659	28,024	17.62	1,590
1959	506,068.46	339,800	377,800	128,268	18.07	7,098
1960	42,053.63	27,885	31,003	11,051	18.53	596
1961	798,747.44	522,820	581,288	217,459	19.00	11,445
1962	13,782.07	8,901	9,896	3,886	19.48	199
1963	102,934.00	65,578	72,912	30,022	19.96	1,504
1964	448.18	282	314	134	20.44	7
1965	230,964.86	143,071	159,071	71,894	20.93	3,435
1966	9,078.19	5,541	6,161	2,917	21.43	136
1967	632,206.34	380,013	422,510	209,696	21.94	9,558
1968	3,205,980.20	1,897,363	2,109,548	1,096,432	22.45	48,839
1969	23,966.84	13,957	15,518	8,449	22.97	368
1970	4,400,615.40	2,521,157	2,803,101	1,597,514	23.49	68,008
1971	13,302.70	7,493	8,331	4,972	24.02	207
1972	26,158,957.10	14,477,675	16,096,733	10,062,224	24.56	409,700

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R1						
NET SALVAGE PERCENT.. 0						
1973	9,578.53	5,207	5,789	3,790	25.10	151
1974	81,268.56	43,368	48,218	33,051	25.65	1,289
1975	74,766.72	39,151	43,529	31,238	26.20	1,192
1976	104,333.63	53,551	59,540	44,794	26.77	1,673
1977	186,882.94	94,019	104,533	82,350	27.33	3,013
1978	392,265.71	193,210	214,817	177,449	27.91	6,358
1979	82,947.09	39,980	44,451	38,496	28.49	1,351
1980	401,265.37	189,177	210,333	190,932	29.07	6,568
1981	1,010,941.86	465,589	517,656	493,286	29.67	16,626
1982	329,087.17	147,971	164,519	164,568	30.27	5,437
1983	1,249,564.20	548,221	609,529	640,035	30.87	20,733
1984	1,767,868.17	756,011	840,557	927,311	31.48	29,457
1985	594,780.51	247,643	275,337	319,444	32.10	9,952
1986	1,215,082.75	492,218	547,263	667,820	32.72	20,410
1987	1,850,237.45	728,661	810,148	1,040,089	33.34	31,196
1988	1,666,528.41	637,214	708,475	958,053	33.97	28,203
1989	429,451.01	159,210	177,015	252,436	34.61	7,294
1990	1,738,644.41	624,330	694,150	1,044,494	35.25	29,631
1991	2,611,302.51	906,827	1,008,239	1,603,064	35.90	44,654
1992	4,115,110.06	1,380,414	1,534,788	2,580,322	36.55	70,597
1993	7,516,764.16	2,432,726	2,704,781	4,811,983	37.20	129,354
1994	3,102,266.77	966,790	1,074,907	2,027,360	37.86	53,549
1995	23,636,129.65	7,082,330	7,874,356	15,761,774	38.52	409,184
1996	3,165,132.68	909,817	1,011,563	2,153,570	39.19	54,952
1997	5,502,353.29	1,514,633	1,684,016	3,818,337	39.86	95,794
1998	44,091,978.26	11,600,159	12,897,420	31,194,558	40.53	769,666
1999	1,981,853.83	496,910	552,480	1,429,374	41.21	34,685
2000	417,130.00	99,506	110,634	306,496	41.88	7,318
2001	815,059.23	184,203	204,803	610,256	42.57	14,335
2002	2,857,217.59	610,416	678,680	2,178,538	43.25	50,371
2003	22,956,953.78	4,616,414	5,132,674	17,824,280	43.94	405,650
2004	2,702,538.22	509,564	566,549	2,135,989	44.63	47,860
2005	1,579,625.81	278,014	309,105	1,270,521	45.32	28,034
2006	513,882.40	83,994	93,387	420,495	46.01	9,139
2007	4,705,608.60	709,276	788,595	3,917,014	46.71	83,858
2008	6,663,420.06	919,552	1,022,387	5,641,033	47.41	118,984
2009	14,691,479.54	1,837,757	2,043,276	12,648,204	48.12	262,847
2010	25,020,314.81	2,806,779	3,120,665	21,899,650	48.83	448,488
2011	2,943,249.59	292,176	324,850	2,618,400	49.54	52,854
2012	4,751,143.70	410,309	456,194	4,294,950	50.25	85,472
2013	6,922,683.16	507,225	563,949	6,358,734	50.97	124,754

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 390 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
SURVIVOR CURVE.. IOWA 55-R1						
NET SALVAGE PERCENT.. 0						
2014	4,711,309.86	282,679	314,291	4,397,019	51.70	85,049
2015	3,629,817.27	170,275	189,317	3,440,500	52.42	65,633
2016	3,575,230.85	120,271	133,721	3,441,510	53.15	64,751
2017	12,965,289.79	261,640	290,900	12,674,390	53.89	235,190
2018	6,829,482.77	45,962	51,102	6,778,381	54.63	124,078
	276,613,563.94	69,577,992	77,358,711	199,254,853		4,788,193
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					41.6	1.73

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - OFFICE MACHINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	61,698.40	58,613	44,145	17,553	0.50	17,553
2012	23,764.11	15,447	11,634	12,130	3.50	3,466
2013	4,855.49	2,671	2,012	2,844	4.50	632
	90,318.00	76,731	57,791	32,527		21,651
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.5						23.97

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - FURNITURE AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	239,473.43	231,492	179,421	60,052	0.50	60,052
2005	665,143.95	598,630	463,977	201,167	1.50	134,111
2006	573,068.01	477,555	370,136	202,932	2.50	81,173
2007	25,407.89	19,479	15,097	10,311	3.50	2,946
2008	863,609.06	604,526	468,546	395,063	4.50	87,792
2009	68,987.13	43,692	33,864	35,123	5.50	6,386
2010	953,124.79	540,107	418,617	534,508	6.50	82,232
2011	486,527.93	243,264	188,545	297,983	7.50	39,731
2012	264,226.94	114,497	88,743	175,484	8.50	20,645
2013	551,666.18	202,279	156,779	394,887	9.50	41,567
2014	269,581.12	80,874	62,683	206,898	10.50	19,705
2015	765,681.81	178,657	138,471	627,211	11.50	54,540
2016	2,471,622.59	411,945	319,283	2,152,340	12.50	172,187
2017	6,170,177.91	617,018	478,228	5,691,950	13.50	421,626
2018	1,364,311.84	45,473	35,245	1,329,067	14.50	91,660
	15,732,610.58	4,409,488	3,417,635	12,314,976		1,316,353

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.4 8.37

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	4,090,552.77	3,681,497	3,511,054	579,499	0.50	579,499
2015	5,077,190.59	3,554,033	3,389,491	1,687,700	1.50	1,125,133
2016	9,396,115.90	4,698,058	4,480,551	4,915,565	2.50	1,966,226
2017	7,649,693.65	2,294,908	2,188,660	5,461,034	3.50	1,560,295
2018	5,744,073.84	574,407	547,814	5,196,260	4.50	1,154,724
	31,957,626.75	14,802,903	14,117,570	17,840,057		6,385,877
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					2.8	19.98

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - AUTOMOBILES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 6-L3						
NET SALVAGE PERCENT.. 0						
2002	90,582.44	90,582	90,582			
2015	752.09	405	752			
2017	2,305.47	573	1,523	782	4.51	173
	93,640.00	91,560	92,857	783		173

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5 0.18

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - LIGHT TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 12-S4						
NET SALVAGE PERCENT.. 0						
2002	764,523.24	725,020	764,523			
2003	89,864.95	84,024	89,865			
2004	39,689.27	36,481	39,689			
2005	270,137.99	242,900	270,138			
2006	457,469.96	400,286	457,470			
2007	601,846.45	507,555	601,846			
2008	802,845.20	644,950	802,845			
2009	662,031.71	498,179	632,502	29,530	2.97	9,943
2010	4,088,837.63	2,824,692	3,586,305	502,533	3.71	135,454
2011	1,269,982.95	786,335	998,352	271,631	4.57	59,438
2012	793,430.84	428,453	543,976	249,455	5.52	45,191
2013	3,195,720.52	1,464,695	1,859,616	1,336,105	6.50	205,555
2014	4,332,776.39	1,624,791	2,062,879	2,269,897	7.50	302,653
2015	4,278,140.61	1,247,805	1,584,247	2,693,894	8.50	316,929
2016	5,548,764.84	1,155,974	1,467,656	4,081,109	9.50	429,590
2017	3,397,928.07	424,741	539,262	2,858,666	10.50	272,254
2018	2,750,732.31	114,623	145,529	2,605,204	11.50	226,539
	33,344,722.93	13,211,504	16,446,700	16,898,023		2,003,546

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.4 6.01

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 14-R4						
NET SALVAGE PERCENT.. 0						
1996	130,266.21	130,266	130,266			
1997	202,652.05	202,652	202,652			
2001	2,173.23	2,037	2,173			
2002	6,881.87	6,312	6,882			
2004	912,469.90	793,201	876,879	35,591	1.83	19,449
2005	203,406.18	169,989	187,922	15,484	2.30	6,732
2006	2,122,365.72	1,685,774	1,863,613	258,753	2.88	89,845
2007	4,271,152.00	3,191,149	3,527,796	743,356	3.54	209,988
2008	8,295,138.21	5,771,011	6,379,817	1,915,321	4.26	449,606
2009	3,157,176.58	2,025,108	2,238,745	918,432	5.02	182,955
2010	7,893,545.70	4,595,149	5,079,909	2,813,637	5.85	480,964
2011	4,044,377.53	2,103,076	2,324,938	1,719,440	6.72	255,869
2012	4,696,834.45	2,137,060	2,362,507	2,334,327	7.63	305,941
2013	7,492,009.97	2,905,851	3,212,400	4,279,610	8.57	499,371
2014	10,424,413.99	3,320,906	3,671,241	6,753,173	9.54	707,880
2015	3,593,131.40	893,145	987,366	2,605,765	10.52	247,696
2016	9,193,523.00	1,635,160	1,807,660	7,385,863	11.51	641,691
2017	7,617,326.79	816,120	902,216	6,715,111	12.50	537,209
2018	4,793,571.78	171,178	189,236	4,604,336	13.50	341,062
	79,052,416.56	32,555,144	35,954,218	43,098,198		4,976,258

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.7 6.29

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - TRACTORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 11-L2						
NET SALVAGE PERCENT.. 0						
1995	177,146.57	154,440	177,147			
2002	44,306.19	32,545	44,306			
2009	57,897.77	33,423	60,091	2,193-		
	279,350.53	220,408	281,544	2,193-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 14-L1.5						
NET SALVAGE PERCENT.. 0						
1960	5,673.50	5,674	5,674			
1961	3,539.00	3,539	3,539			
1962	972.68	973	973			
1963	1,026.82	1,027	1,027			
1966	3,152.61	3,153	3,153			
1967	23,398.38	23,398	23,398			
1968	54,611.08	54,611	54,611			
1969	11,345.85	11,346	11,346			
1970	27,731.60	27,732	27,732			
1971	6,644.50	6,644	6,644			
1972	4,524.32	4,524	4,524			
1973	67,709.54	67,710	67,710			
1974	814.23	814	814			
1975	25,351.71	24,772	25,352			
1976	1,544.50	1,494	1,544			
1978	24,007.27	22,721	24,007			
1988	18,644.38	15,595	18,644			
1994	125,649.32	94,865	125,649			
1995	132,685.56	98,187	132,686			
1996	209,721.43	151,748	208,590	1,131	3.87	292
1997	239,239.39	169,176	232,546	6,693	4.10	1,632
2000	67,159.32	43,989	60,466	6,693	4.83	1,386
2001	16,382.93	10,427	14,333	2,050	5.09	403
2002	174,201.67	107,632	147,949	26,253	5.35	4,907
2003	23,049.70	13,813	18,987	4,063	5.61	724
2004	9,379.42	5,440	7,478	1,901	5.88	323
2005	23,623.28	13,246	18,208	5,415	6.15	880
2006	77,184.28	41,790	57,444	19,740	6.42	3,075
2007	368,948.83	191,853	263,717	105,232	6.72	15,660
2009	7,165.37	3,383	4,650	2,515	7.39	340
2010	308,073.67	136,652	187,839	120,235	7.79	15,435
2011	45,336.50	18,620	25,595	19,742	8.25	2,393
2012	98,806.05	36,770	50,543	48,263	8.79	5,491
2013	70,130.41	22,993	31,606	38,524	9.41	4,094
2014	303,236.60	84,473	116,114	187,123	10.10	18,527
2015	445,680.25	99,962	137,405	308,275	10.86	28,386

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 14-L1.5						
NET SALVAGE PERCENT.. 0						
2016	850,547.86	140,340	192,908	657,640	11.69	56,257
2017	666,229.90	67,576	92,888	573,342	12.58	45,576
2018	386,323.56	13,247	18,209	368,114	13.52	27,227
	4,929,447.27	1,841,909	2,426,502	2,502,945		233,008
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					10.7	4.73

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.6 TRANSPORTATION EQUIPMENT - OTHER VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1946	920.22	920	920			
1962	57.56	58	58			
1965	84,406.50	84,406	84,406			
1972	17,323.55	17,324	17,324			
1973	3,536.26	3,536	3,536			
1974	3,888.93	3,889	3,889			
1983	2,890.72	2,644	2,891			
1992	6,119.39	4,871	6,119			
1993	27,544.80	21,522	27,545			
1994	74,146.19	56,796	74,146			
1995	70,184.76	52,686	70,185			
1996	28,685.34	21,055	28,685			
2000	5,141.00	3,431	4,983	158	4.99	32
2002	1,179,478.95	748,580	1,087,185	92,294	5.48	16,842
2003	302,059.24	186,875	271,404	30,655	5.72	5,359
2005	310,885.69	182,387	264,886	46,000	6.20	7,419
2006	906,063.59	515,251	748,314	157,750	6.47	24,382
2007	365,024.87	200,519	291,220	73,805	6.76	10,918
2008	149,463.48	78,718	114,325	35,138	7.10	4,949
2009	231,325.16	115,663	167,981	63,344	7.50	8,446
2010	281,323.47	131,848	191,487	89,836	7.97	11,272
2011	5,537.55	2,385	3,464	2,074	8.54	243
2012	248,450.64	95,902	139,281	109,170	9.21	11,853
2014	322,483.80	90,512	131,453	191,031	10.79	17,704
2015	200,945.00	44,877	65,176	135,769	11.65	11,654
2016	125,532.09	20,420	29,656	95,876	12.56	7,633
2018	118,132.30	3,937	5,718	112,414	14.50	7,753
	5,071,551.05	2,691,012	3,836,237	1,235,314		146,459

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.4 2.89

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 392.7 TRANSPORTATION EQUIPMENT - MEDIUM TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
SURVIVOR CURVE.. IOWA 8-L4						
NET SALVAGE PERCENT.. 0						
2017	1,995,253.94	374,110	383,972	1,611,282	6.50	247,890
2018	6,914,677.86	432,167	443,559	6,471,119	7.50	862,816
	8,909,931.80	806,277	827,531	8,082,401		1,110,706
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					7.3	12.47

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	134,383.00	111,985	66,660	67,723	2.50	27,089
2007	270,798.56	207,613	123,583	147,216	3.50	42,062
2008	83,816.00	58,671	34,925	48,891	4.50	10,865
2009	54,743.00	34,670	20,638	34,105	5.50	6,201
2010	60,242.00	34,137	20,320	39,922	6.50	6,142
2011	5,183.04	2,592	1,543	3,640	7.50	485
2013	46,416.68	17,020	10,131	36,286	9.50	3,820
2014	770.40	231	138	632	10.50	60
2015	770.40	180	107	663	11.50	58
2016	115,923.80	19,321	11,501	104,423	12.50	8,354
2017	785.81	79	47	739	13.50	55
2018	463,423.36	15,446	9,194	454,229	14.50	31,326
	1,237,256.05	501,945	298,787	938,469		136,517

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.9 11.03

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 394.1 TOOLS, SHOP AND GARAGE EQUIPMENT - CONSTRUCTION TOOLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	11,617.00	8,906	31,889-	43,506	3.50	12,430
	11,617.00	8,906	31,889-	43,506		12,430

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.5 107.00

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 394.2 TOOLS, SHOP AND GARAGE EQUIPMENT - COMMON TOOLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2005	10,526.02	9,473	7,617	2,909	1.50	1,939
2006	10,804.91	9,004	7,240	3,565	2.50	1,426
2014	55,267.65	16,580	13,331	41,937	10.50	3,994
2016	2,088.50	348	280	1,808	12.50	145
2018	952,765.21	31,756	25,533	927,233	14.50	63,947
	1,031,452.29	67,161	54,001	977,452		71,451

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.7 6.93

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 394.3 TOOLS, SHOP AND GARAGE EQUIPMENT - GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1999	824,190.47	803,586	784,572	39,618	0.50	39,618
2000	23,910.82	22,118	21,595	2,316	1.50	1,544
2001	94,843.94	82,988	81,024	13,820	2.50	5,528
2002	223,879.62	184,701	180,331	43,549	3.50	12,443
2003	286,764.74	222,243	216,985	69,780	4.50	15,507
2004	54,167.87	39,272	38,343	15,825	5.50	2,877
2006	3,478.87	2,174	2,123	1,356	7.50	181
2007	21,453.01	12,335	12,043	9,410	8.50	1,107
2008	12,963.09	6,806	6,645	6,318	9.50	665
2010	73,469.80	31,225	30,486	42,984	11.50	3,738
2011	50,175.40	18,816	18,371	31,804	12.50	2,544
2012	22,052.17	7,167	6,997	15,055	13.50	1,115
2013	60,134.71	16,537	16,146	43,989	14.50	3,034
2014	126,931.56	28,560	27,884	99,048	15.50	6,390
2015	83,948.79	14,691	14,343	69,606	16.50	4,219
2016	424,469.01	53,059	51,803	372,666	17.50	21,295
2017	171,250.58	12,844	12,540	158,711	18.50	8,579
2018	118,598.24	2,965	2,895	115,703	19.50	5,933
	2,676,682.69	1,562,087	1,525,126	1,151,556		136,317

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.4 5.09

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 12-R1.5						
NET SALVAGE PERCENT.. 0						
1973	28,014.86	28,015	28,015			
1977	11,826.57	11,827	11,827			
1980	3,955.00	3,955	3,955			
1981	6,017.00	6,017	6,017			
1986	5,472.23	5,472	5,472			
1998	35,800.78	32,608	35,801			
2002	93,979.86	77,141	90,322	3,658	2.15	1,701
	185,066.30	165,035	181,409	3,658		1,701

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.2 0.92

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L3						
NET SALVAGE PERCENT.. 0						
1996	14,418.94	10,403	10,121	4,298	5.57	772
1997	2,320,209.43	1,653,149	1,608,336	711,873	5.75	123,804
1998	7,398,704.24	5,208,688	5,067,491	2,331,213	5.92	393,786
1999	1,031,170.51	717,179	697,738	333,433	6.09	54,751
2001	122,375.76	82,665	80,424	41,952	6.49	6,464
2002	50,892.16	33,665	32,752	18,140	6.77	2,679
2003	644,013.54	415,067	403,815	240,199	7.11	33,783
2005	50,000.00	29,850	29,041	20,959	8.06	2,600
2006	7,909,519.60	4,480,743	4,359,279	3,550,241	8.67	409,486
2007	6,682,064.26	3,554,858	3,458,493	3,223,571	9.36	344,399
2008	1,390,893.17	687,101	668,475	722,418	10.12	71,385
2009	69,265.89	31,377	30,526	38,740	10.94	3,541
2012	745,044.85	238,042	231,589	513,456	13.61	37,726
2013	34,962.40	9,510	9,252	25,710	14.56	1,766
2014	1,089,078.66	243,954	237,341	851,738	15.52	54,880
2015	1,889,807.96	329,771	320,832	1,568,976	16.51	95,032
2016	466,259.31	58,282	56,702	409,557	17.50	23,403
2017	221,177.09	16,588	16,138	205,039	18.50	11,083
2018	18,178,389.54	454,460	442,142	17,736,248	19.50	909,551
	50,308,247.31	18,255,352	17,760,487	32,547,761		2,580,891

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.6 5.13

PECO ENERGY COMPANY
COMMON PLANT

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2018

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	13,659.19	13,204	11,674	1,985	0.50	1,985
2007	20,663.73	15,842	14,006	6,658	3.50	1,902
2008	29,625.38	20,738	18,335	11,290	4.50	2,509
2009	18,269.07	11,570	10,229	8,040	5.50	1,462
2010	511,435.53	289,815	256,229	255,207	6.50	39,263
2011	22,622.02	11,311	10,000	12,622	7.50	1,683
2012	67,989.42	29,462	26,048	41,941	8.50	4,934
2014	497,037.52	149,111	131,832	365,206	10.50	34,782
2015	16,773.27	3,914	3,460	13,313	11.50	1,158
	1,198,075.13	544,967	481,813	716,262		89,678

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.0 7.49

fulBEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046931**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Caroline Fulginiti, hereby state that I am the Vice President and Assistant Controller for Exelon Corporation; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statement and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 4
- PECO Exhibit CF-1
- PECO Exhibit CF-2
- PECO Exhibit CF-3
- PECO Exhibit CF-4

Dated: August 5, 2024

Caroline Fulginiti

PECO Statement No. 5:

Direct Testimony of Paul R. Moul

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-2024-3046931

DIRECT TESTIMONY

WITNESS: PAUL R. MOUL

SUBJECT: OVERALL RATE OF RETURN, INCLUDING CAPITAL STRUCTURE RATIOS, EMBEDDED COST OF DEBT AND THE COST OF EQUITY, FOR PECO ENERGY COMPANY - ELECTRIC DIVISION

DATED: MARCH 28, 2024

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APPENDIX A - Educational Background, Business Experience and Qualifications

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 Approach
Commission	Pennsylvania Public Utility Commission
Company	PECO Energy Company
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
FOMC	Federal Open Market Committee
g	Growth rate
IGF	Internally Generated Funds
LDC	Local Distribution Company
Lev	Leverage modification
LT	Long Term
M&M	Modigliani & Miller
OCI	Other Comprehensive Income
PECO	PECO Energy Company
PUHCA	Public Utility Holding Company Act
r	Represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
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 direct 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 ("Commission") should recognize in determining the revenues that the Electric Division of PECO Energy Company ("PECO" or the "Company") will be authorized to realize at the conclusion of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in PECO 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, 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 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 of 10.95%. The 10.95% rate of return on common equity is composed of a 10.80% cost of equity determined from the results of my proxy group analysis and 0.15% in recognition of the exemplary performance of the Company's management. The 10.80% cost of equity is a blended rate for this case that would apply to both the Electric Division and Gas Division rate cases being filed simultaneously. This blended rate reflects the risk reducing benefits that arise from PECO being a combination utility that has a diversified portfolio of utility investments. The cost of equity for the Electric Division does not include an adjustment I make in my testimony in the accompanying Gas Division rate case to recognize the additional risks of the Gas Division.

My analysis of the Company and its superior performance is based upon the direct testimony of Nicole L. LeVine, the Company's Senior Vice President and Chief Operating Officer, and the direct testimony of other Company witnesses. As shown on page 1 of Schedule 1, I have calculated an 7.98% overall cost of capital for the Company's fully projected future test year ("FPFTY") estimated at December 31, 2025. This return, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish 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 a 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 Nasdaq Global Select Market. Exelon is a component of the S&P 500 Composite Index. PECO provides electric delivery service to approximately 1.7 million electric customers in both the City of Philadelphia and the surrounding counties. Natural gas distribution service is also provided to over half a million customers located in the suburban counties surrounding the City of Philadelphia. Deliveries of electricity to the Company's customers in 2023 were comprised of approximately 38% to residential customers, approximately 21% to commercial customers, approximately 39% to industrial customers, and approximately 2% to street lighting, railroads, and sales for resale. With industrial customers representing 39% of sales, the energy needs of just those customers can have a significant impact on the Company's operations. Indeed, the Company's top ten customers represent 3,466 GWh, or 10% of total sales. PECO 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 that investors rely upon to assess the relative risk, and hence the cost of equity for an electric utility. In this regard, I employed four well-recognized measures of the cost of equity: (1) the Discounted Cash Flow ("DCF") model; (2) the Risk

Premium ("RP") analysis; (3) the Capital Asset Pricing Model ("CAPM"); and (4) 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 Commission's rate of return allowance must be set 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.

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 for my proxy group of ten (10) electric 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, (iv) are not engaged in

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

the construction of a nuclear generating plant, and (v) have not reduced their common dividend in 2023. The companies in 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 has become increasingly problematic. By employing group average data, I have helped to reduce the effect of extraneous influences on the market data for an individual company.

9. Q. What noteworthy factors have influenced your cost of equity analysis?

A. My cost of equity analysis reflects the impact of high levels of inflation, which have not been seen for four decades. Indeed, the rate of inflation spiked upward to 9.1% in June 2022, and by February 2024 it had fallen to 3.2%. High levels of inflation, i.e., those above the Federal Open Market Committee ("FOMC") policy goal of 2%, have an impact on the level of economic activity, the cost of capital – particularly the interest cost of debt, and the need for more cautious financial practices, such as a prudent level of borrowing. While short-term interest rates were at historically low levels during much of the Pandemic, longer-term interest rates began to rise in February 2021 and have continued at higher levels

throughout 2022 and 2023. Following the Pandemic, the accommodative policy by the FOMC has ended, and higher interest rates have occurred. The FOMC uses its open market operations to control the Fed Funds rate as a means of implementing its dual mandate of healthy employment and price stability. This was revealed by the Fed Funds rate, which increased 525 basis points since the beginning of 2022 through 11 increases in 21 months. The FOMC paused its rate increases and held rates steady at its meeting on June 14, 2023. Thereafter, another rate increase occurred on July 26, 2023. The FOMC paused again at its meetings on September 20, November 1, and December 13, 2023, and January 31, 2024. It appears that we are at the end of the current interest rate tightening cycle. Modest reductions in the future would not reduce the Fed Funds rate to Pandemic or pre-Pandemic levels, which were very low after the financial crisis of 2007-08.

10. 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 depending upon extraneous factors that may influence market sentiment. 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.

	Electric Group
DCF	11.37%
Risk Premium	11.50%
CAPM	12.51%
Comparable Earnings	13.25%

To arrive at my recommended equity return, I have incorporated the risk reducing benefits of the combination characteristics of both the Company's electric and gas operations.

11. Q. How have you implemented this risk reduction in your cost of equity recommendation?

A. I accomplished this by focusing on the lower end of the results of my market-based measures of the cost of equity and by removing the leverage adjustment in my DCF calculation. In this regard, I selected as the low end of the range the DCF result for the Electric Group without regard to the leverage adjustment, i.e., 10.40%, and the DCF stated on the same basis in the Company's Gas Division rate case, i.e., 10.74%. By doing so I have reduced the equity return in recognition of the combined utility operations of the Company. That is not to say that diversification in any way changes the fact that the market value leverage and the book value leverage is altered through diversification, but rather it is a convenient way to reduce the return for a combined utility, rather than a stand-alone utility. In this case, the DCF return provides an average of 10.57% (10.40% +10.74% = 21.14% ÷ 2). The Risk Premium result is 11.50% in both cases. The

baseline 10.80% cost of equity for PECO is within this range of returns, i.e., 10.57% and 11.50%. On that basis together with 15 basis points for superior management performance, I recommend that the Commission allow the Company the opportunity to earn a rate of return on common equity of 10.95%. While my recommendation is well within the range of results shown above, there is always the potential that the Company may not actually achieve its allowed rate of return due in the current economic environment. Uncertainty in this regard is related to unanticipated increases in operating and maintenance expenses and the uncertainty associated with commercial and industrial sales. My recommendation should be viewed as the minimum necessary to satisfy investors' expectations. It is important that the Company will have a reasonable opportunity to earn its cost of capital and, in that way, sustain its ability to attract, including maintaining its credit ratings, and retain capital at the level needed to support the increased demand for capital investment that I discuss in more detail in Section II, below.

II. ELECTRIC UTILITY RISK FACTORS

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

A. Electric utilities generally are faced with a variety of challenges that affect their operations, while retaining the obligation to serve under cost of service pricing that continues to dominate their business risk profile.

PECO is part of the PJM Interconnection, L.L.C. ("PJM"). Aside from its traditional responsibility to maintain reliability and comply with the mandates of

PJM, PECO primarily provides delivery service at regulated prices, along with its responsibility for default service.

The risk associated with distributed generation is a major concern for 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.

The cost to replace aging infrastructure also adds to the risk of electric delivery utilities, such as PECO, because these expenditures increase costs without any concomitant increase in revenues, except through regulatory 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. Similarly, the Company is also seeking approval in this case for a Storm Reserve Account. If approved, it would formalize rate recovery of costs over which the Company has no control.

While this clause would alleviate additional regulatory costs and provide customers and the Company with a streamlined, well-defined process that would continue proper regulatory oversight, it would not eliminate the need for rate relief.

PECO has been engaged in an energy efficiency and conservation ("EE&C") programs mandated by Act 129 of 2008, P.L. 1592 ("Act 129"). Costs to the Company from demand response programs such as the Company's EE&C program, which can result in the loss of sales between rate cases.

13. Q. What are the primary risk factors facing the electric delivery utilities industry?

A. A pricing structure restricted by regulation diminishes management's ability to adjust its business strategy quickly to changing market conditions to respond to broadening competition and the potential for bypass arising from self-generation or distributed-generation. The financial structure of the electric business is uncertain due to the adequacy of capital recovery, counter-party risk, potential for financial penalties associated with operational problems, and growth in the utilization of the transmission and distribution network by non-affiliated generators and marketers. Regulatory risks include the overall framework of ratesetting, cost allocation, and rate design issues, and the level of return that will be allowed.

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

A. The Company is faced with the requirement to undertake investment to maintain and upgrade existing facilities in its service territory and to meet growth. Over the next five years, the Company's total capital expenditures (transmission and distribution), as shown in the table below, are expected to be $9.260 million:

Year	Construction
2024	$1,691,000
2025	$1,829,000
2026	$1,930,000
2027	$1,905,000
2028	$1,905,000
Total	$9,260,000

These expenditures represent approximately 71% ($9,260 million ÷ $13,128 million) of the Company's total net utility plant at December 31, 2023. Of the construction expenditures shown above, $6,451,000 million relates to the Company's electric division. A reasonable opportunity to experience a fair rate of return represents the key to a financial profile that will provide the Company with the ability to raise capital in all market conditions to meet its needs, and to satisfy investor requirements in an evolving industry.

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 the determination of the 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 which 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. For this purpose, I have compared PECO to the S&P Public Utilities, an industry-wide proxy consisting of all types of public utility endeavors, and 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 comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4. I have used this group as a broad-based measure of all types of regulated public utility endeavors.

18. Q. What companies comprise your Electric Group?

A. My Electric Group obtained from the Value Line publication 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 an important determinant in analyzing a company's cost of equity 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 directly shown 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 a premium to recognize the higher risk of an equity investment compared to debt.

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

A. Presently, the issuer credit rating for PECO is BBB+ (A on First Mortgage Bonds) from Standard and Poor's Corporation ("S&P") and the Long Term ("LT") issuer rating is A2 (Aa3 on First Mortgage Bonds) from Moody's Investors Services ("Moody's"). The issuer credit rating designation by S&P and LT issuer rating by Moody's focus upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The Company's credit quality is similar to that of the Electric Group, which has an average A2 and BBB+ credit rating from Moody's and S&P, respectively. For the S&P Public Utilities, the average composite credit rating is A3 by Moody's and A- by S&P. Many of the

financial indicators which I will subsequently discuss are considered during the rating process.

21. Q. How do the financial data compare for the Company, PECO, 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 2018-2022. I will highlight the important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, PECO is smaller than the average size of the Electric Group. 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. Historical market-based financial ratios, such as price-earnings multiples 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 which 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.

Since PECO's stock is not traded, there are no market ratios for the Company. The five-year average price-earnings multiple was fairly similar for the Electric Group and the S&P Public Utilities. The five-year average dividend yield for the Electric Group was 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 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 low financial risk, while a firm with a low common equity ratio has high financial risk. The following common equity ratios are computed from balance sheet values that represent book value. The five-year average common equity ratios, based on permanent capital book value, were 53.8% for PECO, 45.1% for the Electric Group, and 40.5% for the S&P Public Utilities. This shows that the financial risk of PECO historically was somewhat less than that of the Electric Group.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative 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 coefficient of variation, the greater degree of variability. During the five-year period, the coefficients of variation were 0.114 (1.3% ÷ 11.4%) for PECO, 0.173 (1.4% ÷ 8.1%) for the Electric Group, and 0.040 (0.4% ÷ 10.0%) for the S&P Public Utilities. These comparisons show that earnings variability for the Company was between the Electric Group and the S&P Public Utilities, albeit much closer to the Electric Group. As a further observation, the direct testimony of Ms. Humphrey has calculated that the equity return in the FPFTY will be 4.31% for the Electric Division. Such return is below the rates of

return generally afforded to public utilities and completely inadequate based upon the Company's historical performance, my cost of equity analysis, and maintenance of its current credit quality ratings.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income). The five-year average operating ratios were 79.8% for PECO, 80.8% for the Electric Group, and 81.0% for the S&P Public Utilities. The operating ratio for PECO was similar to the Electric Group and the S&P Public Utilities.

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 pre-tax interest coverage (excluding AFUDC) was 4.35 times for PECO, 3.02 times for the Electric Group, and 2.94 times for the S&P Public Utilities. The higher interest coverage for PECO suggests lower credit risk.

Quality of Earnings. Measures of earnings quality are usually 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. Quality of earnings has not been a significant concern for PECO, the Electric Group, and 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 construction expenditures was 49.9% for PECO, 65.2% for the Electric Group, and 62.3% for the S&P Public Utilities. The IGF for PECO was considerably weaker than the reference groups, indicating more risk.

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. 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 betas of .88 as the average for the Electric Group provided on page 2 of Schedule 3 and .90 as the average for the S&P Public Utilities provided on page 3 of Schedule 4. The systematic risk was similar for the Electric Group and the S&P Public Utilities.

22. Q. Please summarize your risk evaluation of PECO and the Electric Group.

A. The investment risk of PECO parallels that of the Electric Group in several respects. In certain regards, principally related to its weaker IGF to construction, PECO has higher risk traits. PECO has lower risk as shown by its higher common equity operating ratio, lower earnings variability, and higher interest coverages. Operating ratios and quality earnings indicate comparable risk to the Electric Group. On balance, the cost of equity for the Electric Group would fairly represent the Company's cost of equity for this case.

IV. RECOMMENDED CAPITAL STRUCTURE RATIOS

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

A. The capital structure ratios of PECO should be employed for rate of return purposes. If the operating public utility raises its own debt directly in the capital markets, as PECO does, the operating public utility's own capital structure ratios should be used to determine its overall rate of return. Additionally, if the Company's actual capital structure ratios are used, as they should be, then consistency requires that the embedded cost rates associated with the senior securities reflected in those capital structure ratios should also be employed.

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

A. Yes. The capitalization and capital structure ratios at December 31, 2023, 2024, and 2025 correspond with the end of the historic test year ("HTY"), future test year ("FTY"), and fully projected future test year ("FPFTY"), respectively, in this case. The capitalization and capital structure ratios for the FTY and FPFTY reflect the Company's plan to issue $575 million of new long-term debt in 2024 and $975 million in 2025. There is a $350 million debt maturity in the FPFTY. Future equity financings include $580 million in the FTY and $472 million in the FPFTY. The build-up of retained earnings is also reflected. In presenting the Company's capital structure on Schedule 5, I have removed the call premiums on the early redemption of high-cost long-term debt and preferred stock.

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

A. I have adjusted the principal amounts of long-term debt to exclude the amounts used to finance premiums paid for the early redemption of long-term debt and preferred stock previously redeemed. To do otherwise would deny PECO the opportunity to recover the costs (i.e., a return on and of the money used to fund the call premiums) it incurred solely to redeem high-cost capital. The additional debt PECO issued to finance the call premiums does not increase the Company's rate base. That is to say, no additional rate base was created as a consequence of issuing additional debt and preferred stock to finance the redemptions. Therefore, an adjustment to the capitalization is required to provide the return necessary to service the additional capital PECO issued to fund the call premiums. Thus, while rate base does not change, the return component of the overall cost of capital reflects an adjustment that, when applied to the rate base, furnishes the return necessary to pay the cost of the incremental capitalization that supported the call premiums paid by PECO.

The adjustment for call premiums is appropriate because customers receive all of the cost savings, in the form of a lower overall rate of return, produced by refinancing higher-cost debt and preferred stock, while PECO is simply made whole by recovering the actual costs it incurred to provide these benefits to its customers. In order to produce the savings that resulted from redeeming higher-cost debt and preferred stock, the Company paid to the holders of that debt and preferred stock a premium to surrender their securities prior to maturity. Those

premiums represented an investment made by PECO 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 proper that the Company recover the costs incurred to produce these savings, which consist of a return of and a return on the unamortized premiums. Adjusting the principal amounts in the capital structure provides for the appropriate cost recovery by providing a return on the funds used to pay the premiums, which is reflected as an increment included in the embedded cost rates of PECO's total capital.

26. 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 the amount of short-term debt is well below the construction work in progress ("CWIP") at the end of the FTY and the FPFTY. Exclusion of short-term debt is required because it finances CWIP and hence the cost of short-term debt is reflected in the AFUDC rate. To avoid double-counting, short-term debt must be excluded from the capital structure ratios when setting base rates.

27. Q. What capital structure ratios do you recommend for determining PECO's overall cost of capital in this proceeding?

A. Because rate-setting 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 FPFTY capital structure ratios of 46.60% long-term debt and 53.40% common equity. These

ratios are consistent with the Company's current investment grade credit ratings of A2/BBB+.

V. COSTS OF SENIOR CAPITAL

28. Q. What cost rate have you assigned to the debt portion of PECO'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 Schedule 6, pages 1, 2, and 3, I have computed the weighted average embedded cost rates of long-term debt as of the end of the HTY, FTY, and FPFTY, respectively. For the planned new issues of debt, the Company has budgeted 5.46% as the coupon rate for the two debt issues in each of the years 2024 and 2025. 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 Schedule 6, page 4. 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 for the costs incurred to lower the embedded debt cost rate, which reduces the cost of capital charged to customers.

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

A. I will adopt the 4.58% embedded cost of long-term debt at December 31, 2025, as shown on Schedule 6, page 3. This rate is related to the amount of long-term debt shown in the last three columns of Schedule 5, which provides the basis for the 46.60% long-term debt ratio.

VI. COST OF EQUITY – GENERAL APPROACH

30. 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, 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 also 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, which includes an increment for exemplary management performance.

VII. DISCOUNTED CASH FLOW

31. Q. Please describe the DCF 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-determined 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, which assumes that 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.[2] My DCF results are provided on Schedule 1, page 2, for the Electric Group. The DCF return is 11.78% with the leverage adjustment and 10.40% without the leverage adjustment for the Electric Group. The leverage adjustment is discussed more fully below.

Among the 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

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

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. Other limitations of the DCF include the constant P-E multiple assertion that does not conform with actual stock market performance. And, indeed, the Federal Energy Regulatory Commission has moved to using multiple methods for measuring the cost of equity due to the limitations of the DCF. Further, the DCF method is slow to reflect changes in interest rates. Hence, the DCF should always be used along with other methods that are more responsive to changes in interest rates.

While the results of a DCF analysis should certainly be given weight, the use of more than one method provides a superior foundation for the cost of equity determination. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing). I am aware that the Commission usually expresses its cost of equity determination in the context of the DCF model. But the Commission also considers other methods as well. In its order entered on December 28, 2012, in Docket No. R-2012-2290597, the Commission stated:

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

DCF derived equity return calculation. [3]

Similarly, in the later Aqua Pennsylvania decision, the Commission observed:

> In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[4]

Again, the Commission recognized the need for additional methods in its decision for Columbia Water.

> In *Aqua 2022,* the Commission determined the ROE by using informed judgement based on I&E's DCF and CAPM methodologies. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. We historically have primarily relied upon the DCF methodology in arriving at ROE determinations and utilized the results of the CAPM, as a check upon the reasonableness of the DCF derived equity return, As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our ROE determination.[5]

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[3] *Pennsylvania Public Utility Commission v. PPL Electric Utilities*, R-2012-2290597, meeting held December 5, 2012, at 80.

[4] *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.,* R-2021-3027385, order entered May 16, 2022, at 154-55.

[5] *Pennsylvania Public Utility Commission v. Columbia Water Company,* R-2023-3040258, order entered January 18, 2024, at 108.

The Commission has acknowledged the usefulness of other methods as a means of establishing a range of reasonable returns. Indeed, it is clear that the Commission has been guided by the results of other models and other factors aside from DCF when setting the DSIC return. The Commission's selection of the rate of return on equity for use in the DSIC is usually set well above the cost of equity indicated by the DCF model alone.

32. 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 the dividends an investor receives. 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 2023, the monthly dividend yields are shown on Schedule 7. The month-end prices were adjusted 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 2023, the average dividend yield was 4.03% 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-month and three-month periods were 4.26% and 4.36%, respectively. For applying the DCF model, I have used the six-month average dividend yield of

4.26% 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 investors' anticipated cash flows. 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.[6] This adjustment adds fourteen basis points to the six-month average historical yield, thus producing the 4.40% adjusted dividend yield for the Electric Group.

33. 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 is the DCF model's primary focus because, under the model's assumption that the P-E multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus of prospective growth,

[6] These adjustments are the 1/2 growth approach, the discrete approach, and the quarterly approach. Under the 1/2 approach, the procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, which assumes that half of the dividend payments will be at the expected higher rate during the initial investment period. Under the discrete approach, the "*g*" in the DCF model reflects the discrete growth in the quarterly dividend, which is required for the periodic form of the DCF to properly recognize that dividends are expected to grow on a discrete basis. The quarterly approach takes into account that investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments (D_0) results in this third DCF formulation. This DCF equation provides no further recognition of growth in the quarterly dividend. A compounding of the quarterly dividend yield recognizes the necessity for an adjusted dividend yield.

including historical data and widely available analysts' forecasts of earnings, dividends, book value, and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth (b *x* r), where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s *x* v, where "s" is the number of new common shares that the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses 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 during which a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage during which fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" stage, 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 that are used by investors when pricing common stocks.

34. Q. What factor should be considered in the determination of 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 should be evaluated using a variety of techniques when formulating a judgment of investor-expected growth.

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

A. I considered the growth in the financial variables shown on Schedules 8 and 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth 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, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and, with the constant P-E multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates, which were also reviewed to gain a perspective on the industry, were obtained from the Value Line publication that provides this data. While historical data cannot be ignored, they are much less significant when applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double-counted because they are already factored into analysts' forecasts of earnings growth.

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

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, 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 investors' expected return. The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the price-earnings ("P-E") multiple. 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 investors' expectations of their actual total return. Moreover, academic research also focuses on five-year growth rates specifically because market outcomes occurring over that investment horizon are what influence stock prices. Indeed, if investors required forecasts beyond five years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points in order to make informed decisions to purchase and sell stocks.

37. 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, and Value Line. These are all reliable authorities of projected growth that investors use to make buy, sell, and hold decisions. The IBES/First Call and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a

survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. 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 and Zacks 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 for the Electric Group are also included on Schedule 9.

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

A. Schedule 9 shows the prospective five-year earnings per share growth rates18 projected for the Electric Group by IBES/First Call (7.18%), Zacks (5.28%), and Value Line (5.33%).

39. Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While a variety of factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. 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 fact, Professor Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[7] Consistent with Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations.

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

A. The forecasts shown on Schedule 9 for the Electric Group exhibit a range of average earnings per share growth rates from 5.28% to 7.18%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 6.00% is a reasonable estimate of investor-expected growth for the Electric Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates. The reasonableness of this growth rate is also supported by the expected continuation of electric utility infrastructure spending.

41. Q. Are the dividend yield and growth components of the DCF adequate to accurately depict the rate of return on common equity when it is used to calculate a utility's weighted average overall cost of capital?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Electric Group, average capital structure ratios are 37.91% long-

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

term debt, 0.36% preferred stock, and 61.74% common equity, as shown on Schedule 10. These ratios are calculated from market values based on the fair value of debt and preferred stock, if any, and the price of each company's common stock. Hence, all values here related to the investors' valuation of debt and equity in the capital markets. If book values are used to compute the capital structure ratios, then a leverage adjustment is required in the case where the capital structure ratios vary from market values.

42. Q. What is a leverage adjustment?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

43. Q. Why is a leverage adjustment appropriate?

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 from the capital structure 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-valued capitalization of a firm. If the ratemaking 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 ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's 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,"[8] provide a return of 9.07% when applicable to a capital structure with 100% common equity.

44. Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

[8] Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance, and the Theory of Investments," American Economic Review, June 1958, at 261-97. Franco Modigliani and Merton H. Miller, "Taxes and the Cost of Capital: A Correction," American Economic Review, June 1963, at 433-43.

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 market prices relative to book value are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to 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. Stock prices above book value are common for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins. 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 actually 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: when the market capitalization declines, the

leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

45. 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. What I label 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) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I were to express my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and 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 9.07%, which is the return for the Electric Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 2.67% to compensate investors for the risk of a 55.23% debt ratio and 0.04% for a 0.46% preferred stock ratio. These are the book-value ratios that differ markedly from the market-value based ratios I discussed previously. Under this approach, the parts add up to 11.78% (9.07% + 2.67% + 0.04%), 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 added the 4.40% dividend yield, the 6.00% growth rate, and 1.38% for the leverage adjustment in order to arrive at the same 11.78% (4.40% + 6.00% + 1.38%) return. I know of no means to mathematically solve for the 1.38% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.38% adjustment is merely a convenient way to compare the 11.78% return computed using the Modigliani & Miller formulas to the 10.40% return generated by the DCF model (i.e., D_1/P_0 + g, or the traditional form of the DCF shown on Schedule 1, page 2) based on a market-value capital structure. A 10.40% 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.

46. Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

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 ratemaking process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is 11.78%, computed as follows:

	D_1/P_0	+	g	+	*lev.*	=	K
Electric Group	4.40%	+	6.00%	+	1.38%	=	11.78%

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 P-E multiple. An assumption that there will be no change in the P-E multiple is not supported by the realities of the equity market because P-E multiples do not remain constant. This is one of the constraints of this model that makes it important to consider the results of other models when determining a company's cost of equity.

VIII. RISK PREMIUM ANALYSIS

47. 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 Schedule 1, page 2. That result is 11.50%.

48. 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 5.00% yield represents a reasonable estimate of the prospective yield on long-term, public utility bonds. The 5.00% public utility bond yield I used in the Risk Premium method is very conservative given current interest rates.

49. Q. What historical data are shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on Schedule 11, page 1. For the 12 months ended December 2023 the average monthly yield on Moody's index public utility bonds was 5.54%. For the six- and three-month periods ended December 2023, the yields were 5.78% and 5.91%, respectively. During the 12 months ended December 2023, the range of the yields on public utility bonds were 5.13% to 6.34%. 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 1.45% on a twelve-month average basis, 1.37% on a six-month average basis, and 1.32% on a three-month average basis. With these data, 1.25% represents a reasonable, albeit conservative, spread for the yield on A-rated public utility bonds over Treasury bonds.

50. 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 Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields

that I describe above. Blue Chip is a reliable authority and contains consensus forecasts of various interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip 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 December 28, 2023, and a yield spread of 1.25%, derived from recent historical data.

51. 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 have also 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
2024	First	5.1%	6.1%	4.3%	1.25%	5.55%
2024	Second	5.0%	6.0%	4.3%	1.25%	5.55%
2024	Third	4.9%	6.0%	4.2%	1.25%	5.45%
2024	Fourth	4.8%	5.9%	4.1%	1.25%	5.35%
2025	First	4.8%	5.8%	4.0%	1.25%	5.25%
2025	Second	4.7%	5.8%	4.0%	1.25%	5.25%

52. 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, 2023 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
2025-2029	4.9%	6.0%	4.1%
2030-2034	5.0%	6.0%	4.2%

The longer-term forecasts by Blue Chip suggest that interest rates will continue to be above pre-Pandemic levels. A 5.00% yield on A-rated public utility bonds represents a reasonably conservative benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are based on forecasts available to investors, who regularly rely upon such data to make investment decisions. In this case, I have taken a conservative approach in selecting a 5.00% yield on A-rated public utility bonds, because current rates and forecasts would support a higher rate. My rate will accommodate reductions that may occur later in 2024.

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

A. To develop an appropriate equity risk premium, I analyzed the results from 2022 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 Schedule 12, page 1.

Common Equity Risk Premiums	
Low Interest Rates	7.13%
Average Across All Interest Rates	5.96%
High Interest Rates	4.76%

Based on my analysis of the historical data, the equity risk premium was 7.13% when the marginal cost of long-term government bonds was low (i.e., 2.83%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.03% on average during periods of high interest rates), the spread narrowed to 4.76%. Over the entire spectrum of interest rates, the equity risk premium was 5.96% when the average government bond yield was 4.91%. From these data, I have utilized a 6.50% equity risk premium. The equity risk premium of 6.50% is between the premiums associated with low interest rates (i.e., 7.13%) and average for the entire historical period interest rates (i.e., 5.96%).

54. 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 5.00% + 6.50% = 11.50%

IX. CAPITAL ASSET PRICING MODEL

55. 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 13.25% for the Electric Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 11.02% (13.25% - (0.27 x 8.26%)) through use of the Value Line beta excluding the leverage adjustment (i.e., 1.15 - 0.88 = 0.27). 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.

56. 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 0.88 for the Electric Group.

57. 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 Value Line betas are measured over a five-year period. The betas must be reflective of the financial risk associated with the ratemaking 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. Since we used book values in this case, the Value Line betas must be adjusted for the higher financial risk associated with the book value capital structure. 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,[9] as follows:

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

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 0.63 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 1.15 for the book value capital structure of the Electric Group.

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

[9] 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, Dec. 27-29, 1971. (May 1972), pp. 435-52.

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 2023, the average yield on 30-year Treasury bonds was 4.09%. For the six- and three-months ended December 2023, the yields on 30-year Treasury bonds were 4.41% and 4.58%, respectively. During the twelve months ended December 2023, the range of the yields on 30-year Treasury bonds was 3.66% to 4.95%. The low yields that existed during 2020 can be traced to extraordinary events associated with the Pandemic that jolted the capital markets. Due to high inflation rates above the policy goal of the FOMC, the accommodative policy was ended by the FOMC in the first quarter of 2022. A tighter monetary policy was put in place and resulted in higher interest rates that have already occurred. After the FOMC ended its bond-buying program (i.e., quantitative easing) in March 2022, it is in the process of running off its $9 trillion asset portfolio, which will keep interest rates at elevated levels.

High interest rates clearly point to high capital costs, as indicated by recent bond yields. The yield on 10-year Treasury bonds moved above the 3% level on May 2, 2022, for the first time since late 2018. By December 2023, the yield on 30-year Treasury bonds moved to 4.14%, or an increase of 2.47% (or 148%) since December 2020.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on December 28, 2023, indicate that the yields on long-term Treasury bonds are expected to be in the range of 4.0% to 4.3% during the next six quarters. This means that elevated interest rates will continue near current levels. The longer-

term forecasts show that the yields on 30-year Treasury bonds will average 4.1% from 2025 through 2029 and 4.2% from 2030 to 2034. Hence, I have used a conservative 3.75% risk-free rate of return for CAPM purposes, which considers the possibility of some moderation of rates prospectively.

59. 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 12.21% (12.40% + 12.02% = 24.42% ÷ 2) as the midpoint of the "low" and "average" interest rate environments. During those periods, the yield on long-term government bonds was 3.87% (2.83% + 4.91% = 7.74% ÷ 2). The resulting market premium is 8.34% (12.21% - 3.87%) based on historical data, as shown on page 2 of Schedule 13. As also shown on page 2 of Schedule 13, I calculated the forecast returns, which show a 11.93% total market return based on the Value Line forecasts. With these data, I calculated a market premium of 8.18% (11.93% - 3.75%) using the forecast data by Value Line. The resulting market premium applicable to the CAPM derived from these sources equals 8.26% (8.18% + 8.34% = 16.52% ÷ 2).

60. Q. What does your CAPM analysis show?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 1.15 for the Electric Group, and the 8.26% market premium, the following result is indicated.

$$Rf + \beta \times (Rm-Rf) = k$$

Electric Group $3.75\% + 1.15 \times (8.26\%) = 13.25\%$

The CAPM results shown here should receive more weight in an environment of rising interest rates, because the DCF will provide an understated result. Indeed, the Commission has used the results of the CAPM when the DCF is producing atypical results as noted previously regarding the Aqua Pennsylvania order.

X. COMPARABLE EARNINGS APPROACH

61. 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 risk 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.[10]

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.

62. 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

[10] *Bluefield* at 668.

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 definition for these parameters is provided on Schedule 14, page 3. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Schedule 14, page 1.

I relied upon Value Line data 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 Schedule 14, page 2, 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.

63. 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 misspecification contained 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 13.1% using only the returns that were less than 20%, as shown on Schedule 14, page 2. The average forecasted rate of return as published by Value Line is 13.4% also using values less than 20%, as provided on Schedule 14, page 2. Using the average of these data, my Comparable Earnings result is 13.25%, as shown on Schedule 1, page 2.

XI. CONCLUSION ON COST OF EQUITY

64. 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, which includes fifteen basis points (or 0.15%) for recognition of the Company's strong management performance. My cost of equity recommendation is within the range of results and should be considered in the

context of the Company's risk characteristics relative to the Electric Group companies. The additional 15 basis points is well within the range of management performance provisions that the Commission has recognized previously, which has been between 5 basis points and 25 basis points.

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. In summary, the Company should be provided an opportunity to realize an 10.95% rate of return on common equity so that it can compete in the capital markets, attain reasonable credit quality, sustain its cash flow in the context of its high levels of capital expenditures, and receive recognition of the significant accomplishments that management has achieved.

65. Q. Does this complete your direct testimony?

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.

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 Exhibit PRM-1:

Cost of Capital and Fair Rate of Return

PECO Exhibit PRM-1

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
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PECO Energy Company
Proposed Rate of Return
Estimated at December 31, 2025

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.60%	4.58%	2.13%
Common Equity	53.40%	10.95%	5.85%
Total	100.00%		7.98%

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 29.3121% composite federal and state income tax rate
(10.41% ÷ 2.13%) 4.89 x

Post-tax coverage of interest expense
(7.98% ÷ 2.13%) 3.75 x

PECO - Electric
Cost of Equity
as of December 31, 2023

Market Models (DCF, RP & CAPM)

Discounted Cash Flow (DCF)	D_1/P_0 (1)	+	*g* (2)	+	*lev.* (3)	=	*k*	
Electric Group	4.40%	+	6.00%	+	1.38%	=	11.78%	
Risk Premium (RP)			*I* (4)	+	*RP* (5)	=	*k*	
Electric Group			5.00%	+	6.50%	=	11.50%	
Capital Asset Pricing Model (CAPM)	*Rf* (6)	+	*ß* (7)	*x (*	*Rm-Rf* (8)	*) =*	*k*	
Electric Group	3.75%	+	1.15	x (	8.26%	) =	13.25%	

Book Value Method

	Historical	*Forecast*	**Average**
Comparable Earnings (CE) (10)			
Comparable Earnings Group	13.1%	13.4%	13.25%

References:
(1) Schedule 07
(2) Schedule 09
(3) Schedule 10
(4) A-rated public utility bond yield comprised of a 3.75% risk-free rate of return and a yield spread of 1.25% (Schedule 11 page 3)
(5) Schedule 07
(6) Schedule 09
(7) Schedule 10
(8) Schedule 07
(9) Schedule 09
(10) Schedule 10

PECO Energy Company
Capitalization and Financial Statistics
2018-2022, Inclusive

	2022	2021	2020	2019	2018	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$10,359.0	$ 9,493.0	$ 8,470.0	$ 7,767.0	$ 7,088.0	
Short-Term Debt	$ 239.0	$ -	$ 40.0	$ -	$ -	
Total Capital	$10,598.0	$ 9,493.0	$ 8,510.0	$ 7,767.0	$ 7,088.0	
Capital Structure Ratios						Average
Based on Permanent Capital:						
Long-Term Debt	46.3%	46.1%	46.5%	46.2%	46.1%	46.2%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity [1]	53.7%	53.9%	53.5%	53.8%	53.9%	53.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	47.5%	46.1%	46.7%	46.2%	46.1%	46.5%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity [1]	52.5%	53.9%	53.3%	53.8%	53.9%	53.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [1]	10.8%	10.5%	10.3%	13.2%	12.4%	11.4%
Operating Ratio [2]	79.5%	79.6%	82.1%	77.0%	80.6%	79.8%
Coverage incl. AFUDC [3]						
Pre-tax: All Interest Charges	4.70 x	4.20 x	3.84 x	5.36 x	4.48 x	4.52 x
Post-tax: All Interest Charges	4.25 x	4.13 x	4.04 x	4.88 x	4.43 x	4.35 x
Overall Coverage: All Int. & Pfd. Div.	4.25 x	4.13 x	4.04 x	4.88 x	4.43 x	4.35 x
Coverage excl. AFUDC [3]						
Pre-tax: All Interest Charges	4.46 x	3.99 x	3.68 x	5.24 x	4.39 x	4.35 x
Post-tax: All Interest Charges	4.02 x	3.92 x	3.88 x	4.76 x	4.34 x	4.18 x
Overall Coverage: All Int. & Pfd. Div.	4.02 x	3.92 x	3.88 x	4.76 x	4.34 x	4.18 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.3%	6.7%	5.1%	3.2%	2.6%	5.0%
Effective Income Tax Rate	12.1%	2.3%	-7.2%	11.0%	1.3%	3.9%
Internal Cash Generation/Construction [4]	48.9%	42.3%	39.7%	59.6%	59.0%	49.9%
Gross Cash Flow/ Avg. Total Debt [5]	22.5%	20.7%	21.0%	26.8%	25.4%	23.3%
Gross Cash Flow Interest Coverage [6]	6.92 x	6.30 x	6.39 x	7.70 x	6.96 x	6.85 x
Common Dividend Coverage [7]	2.65 x	2.55 x	2.34 x	2.56 x	2.64 x	2.55 x

See Page 2 for Notes.

PECO Energy Company
Capitalization and Financial Statistics
2018-2022, 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 a percentage calculated as 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 total debt.
(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: SEC Form 10-K
Utility COMPUSTAT

Electric Group
Capitalization and Financial Statistics [1]
2018-2022, Inclusive

	2022	2021	2020	2019	2018	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 56,763.6	$ 55,240.3	$ 54,211.8	$ 52,064.3	$ 46,943.9	
Short-Term Debt	$ 2,137.3	$ 1,777.2	$ 1,638.4	$ 1,473.9	$ 1,960.6	
Total Capital	$ 58,900.9	$ 57,017.5	$ 55,850.2	$ 53,538.2	$ 48,904.5	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	25 x	24 x	26 x	20 x	19 x	23 x
Market/Book Ratio	200.9%	197.3%	186.0%	197.4%	187.8%	193.9%
Dividend Yield	3.4%	3.8%	4.0%	3.7%	3.9%	3.8%
Dividend Payout Ratio	78.8%	79.7%	96.3%	69.7%	70.5%	79.0%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	54.1%	52.3%	54.1%	52.0%	52.2%	52.9%
Preferred Stock	2.0%	2.1%	2.3%	2.1%	1.5%	2.0%
Common Equity [2]	43.9%	45.5%	43.6%	45.9%	46.4%	45.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	55.8%	53.8%	55.5%	53.4%	54.0%	54.5%
Preferred Stock	2.0%	2.1%	2.2%	2.0%	1.4%	1.9%
Common Equity [2]	42.3%	44.1%	42.3%	44.6%	44.6%	43.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	6.7%	7.5%	7.4%	8.7%	10.2%	8.1%
Operating Ratio [3]	84.3%	84.9%	79.3%	78.7%	76.7%	80.8%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.48 x	2.89 x	2.70 x	3.00 x	3.48 x	3.11 x
Post-tax: All Interest Charges	3.09 x	2.60 x	2.47 x	2.66 x	2.97 x	2.76 x
Overall Coverage: All Int. & Pfd. Div.	3.08 x	2.58 x	2.46 x	2.65 x	2.91 x	2.74 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.38 x	2.81 x	2.61 x	2.91 x	3.39 x	3.02 x
Post-tax: All Interest Charges	2.99 x	2.52 x	2.38 x	2.57 x	2.89 x	2.67 x
Overall Coverage: All Int. & Pfd. Div.	2.98 x	2.51 x	2.37 x	2.57 x	2.83 x	2.65 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	6.6%	8.2%	6.5%	4.8%	5.5%	6.3%
Effective Income Tax Rate	18.0%	15.9%	9.2%	17.3%	20.0%	16.1%
Internal Cash Generation/Construction [5]	59.6%	61.2%	60.3%	67.1%	78.0%	65.2%
Gross Cash Flow/ Avg. Total Debt [6]	14.9%	14.7%	15.4%	17.4%	19.3%	16.3%
Gross Cash Flow Interest Coverage [7]	6.62 x	5.17 x	4.84 x	4.84 x	5.45 x	5.38 x
Common Dividend Coverage [8]	3.10 x	3.08 x	3.09 x	3.38 x	3.75 x	3.28 x

See Page 2 for Notes.

Electric Group
Capitalization and Financial Statistics
2018-2022, 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, (iv) are not engaged in the construction of a nuclear generating plant or have not recently cancelled the construction of a nuclear generating plant, and (v) have not recently reduced its common dividend.

		Corporate Credit Ratings		Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Beta
AGR	AVANGRID, Inc (AGR)	A3	A-	NYSE	0.85
ED	Consolidated Edison Inc (ED)	Baa1	A-	NYSE	0.75
D	Dominion Energy, Inc. (D)	A2	BBB+	NYSE	0.85
DUK	Duke Energy Corporation (DUK)	A2	BBB+	NYSE	0.85
ES	Eversource Energy (ES)	A2	A	NYSE	0.90
EXC	Exelon Corp (EXC)	A2	BBB+	NDQ	NMF
FE	FirstEnergy Corp (FE)	A3	BBB	NYSE	0.85
NEE	NextEra Energy Inc (NEE)	A1	A	NYSE	0.95
PPL	PPL Corp (PPL)	A3	A	NYSE	1.05
PEG	Public Service Enterprise Group	A3	A-	NYSE	0.90
	Average	A3	A-		0.88

Note: Ratings are those of utility subsidiaries

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]
2018-2022, Inclusive

	2022	2021	2020	2019	2018	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 42,136.6	$ 40,154.3	$ 38,732.9	$ 36,461.6	$ 32,871.6	
Short-Term Debt	$ 1,713.7	$ 1,397.4	$ 1,154.1	$ 1,221.9	$ 1,420.3	
Total Capital	$ 43,850.3	$ 41,551.7	$ 39,887.0	$ 37,683.5	$ 34,291.9	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	23 x	22 x	23 x	20 x	21 x	22 x
Market/Book Ratio	219.2%	220.7%	218.2%	220.9%	204.4%	216.7%
Dividend Yield	3.3%	3.5%	3.6%	3.2%	3.5%	3.4%
Dividend Payout Ratio	72.5%	72.9%	78.0%	62.7%	68.7%	71.0%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	58.3%	57.4%	58.1%	56.7%	55.0%	57.1%
Preferred Stock	2.2%	2.3%	2.6%	2.4%	2.5%	2.4%
Common Equity [2]	39.6%	40.4%	39.4%	41.0%	42.5%	40.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	60.0%	58.9%	59.4%	58.1%	57.0%	58.7%
Preferred Stock	2.1%	2.2%	2.5%	2.3%	2.4%	2.3%
Common Equity [2]	37.9%	38.9%	38.1%	39.6%	40.7%	39.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	9.9%	9.4%	10.2%	10.3%	10.3%	10.0%
Operating Ratio [3]	83.1%	83.1%	79.8%	79.3%	79.8%	81.0%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.28 x	3.16 x	2.80 x	3.05 x	2.94 x	3.05 x
Post-tax: All Interest Charges	2.94 x	2.87 x	2.60 x	3.10 x	2.59 x	2.82 x
Overall Coverage: All Int. & Pfd. Div.	2.89 x	2.81 x	2.55 x	3.04 x	2.55 x	2.77 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.17 x	3.06 x	2.70 x	2.95 x	2.84 x	2.94 x
Post-tax: All Interest Charges	2.84 x	2.78 x	2.50 x	3.00 x	2.48 x	2.72 x
Overall Coverage: All Int. & Pfd. Div.	2.79 x	2.72 x	2.46 x	2.94 x	2.44 x	2.67 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.1%	7.4%	6.8%	6.0%	7.3%	6.9%
Effective Income Tax Rate	12.9%	10.6%	9.9%	12.2%	42.0%	17.5%
Internal Cash Generation/Construction [5]	60.2%	60.5%	58.6%	65.9%	66.2%	62.3%
Gross Cash Flow/ Avg. Total Debt [6]	15.1%	15.0%	15.9%	17.5%	17.4%	16.2%
Gross Cash Flow Interest Coverage [7]	5.70 x	5.17 x	4.90 x	4.97 x	4.98 x	5.14 x
Common Dividend Coverage [8]	3.49 x	3.47 x	3.52 x	5.56 x	4.80 x	4.17 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2018-2022, 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	Credit Rating [1] S&P	Common Stock Traded	Value Line Beta
Alliant Energy Corporation	LNT	Baa1	A-	NYSE	0.85
Ameren Corporation	AEE	Baa1	BBB+	NYSE	0.85
American Electric Power	AEP	Baa1	A-	NYSE	0.75
American Water Works	AWK	Baa1	A	NYSE	0.90
CenterPoint Energy	CNP	Baa1	BBB+	NYSE	1.10
CMS Energy	CMS	Baa1	A-	NYSE	0.80
Consolidated Edison	ED	Baa1	A-	NYSE	0.75
Dominion Energy	D	A2	BBB+	NYSE	0.85
DTE Energy Co.	DTE	A2	A-	NYSE	0.95
Duke Energy	DUK	A2	BBB+	NYSE	0.85
Edison Int'l	EIX	Baa1	BBB	NYSE	0.95
Entergy Corp.	ETR	Baa1	BBB+	NYSE	0.95
Evergy, Inc.	EVRG	Baa1	A-	NYSE	0.90
Eversource	ES	A3	A	NYSE	0.90
Exelon Corp.	EXC	A2	BBB+	NDQ	NMF
FirstEnergy Corp.	FE	A3	BBB	NYSE	0.85
NextEra Energy Inc.	NEE	A1	A	NYSE	0.95
NiSource Inc.	NI	Baa2	BBB+	NYSE	0.85
NRG Energy Inc.	NRG	Ba1	BB	NYSE	1.10
Pinnacle West Capital	PNW	A3	BBB+	NYSE	0.90
PPL Corp.	PPL	A3	A	NYSE	1.05
Public Serv. Enterprise Inc.	PEG	A3	A-	NYSE	0.90
Sempra Energy	SRE	A3	BBB+	NYSE	0.95
Southern Co.	SO	Baa1	BBB+	NYSE	0.90
WEC Energy Corp.	WEC	A2	A-	NYSE	0.80
Xcel Energy Inc	XEL	A2	A-	NYSE	0.80
Average for S&P Utilities		A3	BBB+		0.90

Note: [1] Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service, Inc.
S&P Global Inc.
The Value Line Investment Survey

PECO Energy Company
Capitalization and Related Capital Structure Ratios
Actual at December 31, 2023 and Estimated at December 31, 2024 and December 31, 2025

	Actual at December 31, 2023			Estimated at December 31, 2024			Estimated at December 31, 2025		
		Capital Structure Ratios			Capital Structure Ratios			Capital Structure Ratios	
	Amount Outstanding	Incl. S-T Debt	Excl. S-T Debt	Amount Outstanding	Incl. S-T Debt	Excl. S-T Debt	Amount Outstanding	Incl. S-T Debt	Excl. S-T Debt
	($000)			($000)			($000)		
Long-Term Debt [1]	$ 5,383,555	46.34%	47.01%	$ 5,958,830 [2]	46.17%	46.60%	$ 6,583,898 [2]	46.10%	46.60%
Common Equity									
Common Stock	1,423,004			1,423,004			1,423,004		
Other Paid-In Capital	2,627,349			3,207,349 [4]			3,679,349 [5]		
Retained Earnings [3]	2,019,166			2,197,166 [5]			2,442,166 [4]		
Total Common Equity	6,069,519	52.24%	52.99%	6,827,519	52.90%	53.40%	7,544,519	52.83%	53.40%
Total Permanent Capital	11,453,074	98.58%	100.00%	12,786,349	99.07%	100.00%	14,128,417	98.93%	100.00%
Short-Term Debt	164,783	1.42%		120,179	0.93%		153,029	1.07%	
Total Capital Employed	$ 11,617,857	100.00%		$ 12,906,528	100.00%		$ 14,281,446	100.00%	

Notes:
[1] Includes current portion of long-term debt.
[2] Reflects change in long-term debt consisting of:

New issue(s)	$ 575,000	$ 975,000
Maturity		$ (350,000)
Change in Adjustment for Tenders and Calls	$ 278	$ 68

[3] Excludes Accumulated Other Comprehensive Income
[4] Equity Infusions $ 580,000 | 472,000
[5] Reflects change in retained earnings consisting of:

Net income	$ 570,000	$ 763,000
Common Dividends	$ (400,000)	$ (534,000)
Tax Sharing Benefit	$ 8,000	$ 16,000

Source of Information: Company provided data

PECO Energy Company
Calculation of the Embedded Cost of Long-Term Debt
Actual at December 31, 2023

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
First and Refunding Mortgage Bonds					
3.15%	10/15/25	$ 350,000,000	6.50%	3.29%	0.21%
5.90%	05/01/34	75,000,000	1.39%	6.00%	0.08%
5.95%	10/01/36	300,000,000	5.57%	6.04%	0.34%
5.70%	03/15/37	175,000,000	3.25%	5.81%	0.19%
4.80%	10/15/43	250,000,000	4.64%	4.89%	0.23%
4.15%	10/01/44	300,000,000	5.57%	4.21%	0.23%
3.70%	09/15/47	325,000,000	6.04%	3.77%	0.23%
3.90%	03/01/48	650,000,000	12.07%	4.08%	0.49%
3.00%	09/15/49	325,000,000	6.04%	3.10%	0.19%
2.80%	06/15/50	350,000,000	6.50%	2.86%	0.19%
3.05%	03/01/51	375,000,000	6.97%	3.11%	0.22%
2.85%	09/15/51	375,000,000	6.97%	2.90%	0.20%
4.60%	05/15/52	350,000,000	6.50%	4.71%	0.31%
4.38%	08/15/52	425,000,000	7.89%	4.46%	0.35%
4.90%	06/15/33	575,000,000	10.68%	5.03%	0.54%
Trust Preferred Capital Securities					
7.38%	04/06/28	80,520,619	1.50%	7.46%	0.11%
6.75%	04/06/28	805,206	0.02%	6.75%	0.00%
5.75%	06/15/33	103,092,784	1.92%	5.88%	0.11%
		5,384,418,609	100.00%		4.22%
Adjustment for Tenders and Calls		(864,000)			
Long-Term Debt		$ 5,383,554,609			
Annualized Cost		$ 227,222,465			
Adjustment for Tenders and Calls on Reacquired Debt		341,000			
Total Cost		$ 227,563,465			4.23%

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
Estimated at December 31, 2024

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
First and Refunding Mortgage Bonds					
3.15%	10/15/25	$ 350,000,000	5.87%	3.29%	0.19%
5.90%	05/01/34	75,000,000	1.26%	6.00%	0.08%
5.95%	10/01/36	300,000,000	5.03%	6.04%	0.30%
5.70%	03/15/37	175,000,000	2.94%	5.81%	0.17%
4.80%	10/15/43	250,000,000	4.20%	4.89%	0.21%
4.15%	10/01/44	300,000,000	5.03%	4.21%	0.21%
3.70%	09/15/47	325,000,000	5.45%	3.77%	0.21%
3.90%	03/01/48	650,000,000	10.91%	4.08%	0.45%
3.00%	09/15/49	325,000,000	5.45%	3.10%	0.17%
2.80%	06/15/50	350,000,000	5.87%	2.86%	0.17%
3.05%	03/01/51	375,000,000	6.29%	3.11%	0.20%
2.85%	09/15/51	375,000,000	6.29%	2.90%	0.18%
4.60%	05/15/52	350,000,000	5.87%	4.71%	0.28%
4.38%	08/15/52	425,000,000	7.13%	4.46%	0.32%
4.90%	06/15/33	575,000,000	9.65%	5.03%	0.49%
5.46%	09/01/54	575,000,000	9.65%	5.53%	0.53%
Trust Preferred Capital Securities					
7.38%	04/06/28	80,520,619	1.35%	7.46%	0.10%
6.75%	04/06/28	805,206	0.01%	6.75%	0.00%
5.75%	06/15/33	103,092,784	1.73%	5.88%	0.10%
		5,959,418,609	100.00%		4.36%
Adjustment for Tenders and Calls		(589,000)			
Long-Term Debt		$ 5,958,829,609			
Annualized Cost		$ 259,830,651			
Adjustment for Tenders and Calls on Reacquired Debt		68,000			
Total Cost		$ 259,898,651			4.36%

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
Estimated at December 31, 2025

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
First and Refunding Mortgage Bonds					
5.90%	05/01/34	$ 75,000,000	1.14%	6.00%	0.07%
5.95%	10/01/36	300,000,000	4.56%	6.04%	0.28%
5.70%	03/15/37	175,000,000	2.66%	5.81%	0.15%
4.80%	10/15/43	250,000,000	3.80%	4.89%	0.19%
4.15%	10/01/44	300,000,000	4.56%	4.21%	0.19%
3.70%	09/15/47	325,000,000	4.94%	3.77%	0.19%
3.90%	03/01/48	650,000,000	9.87%	4.08%	0.40%
3.00%	09/15/49	325,000,000	4.94%	3.10%	0.15%
2.80%	06/15/50	350,000,000	5.32%	2.86%	0.15%
3.05%	03/01/51	375,000,000	5.70%	3.11%	0.18%
2.85%	09/15/51	375,000,000	5.70%	2.90%	0.17%
4.60%	05/15/52	350,000,000	5.32%	4.71%	0.25%
4.38%	08/15/52	425,000,000	6.46%	4.46%	0.29%
4.90%	06/15/33	575,000,000	8.73%	5.03%	0.44%
5.46%	09/01/54	575,000,000	8.73%	5.53%	0.48%
5.46%	09/01/55	975,000,000	14.81%	5.53%	0.82%
Trust Preferred Capital Securities					
7.38%	04/06/28	80,520,619	1.22%	7.46%	0.09%
6.75%	04/06/28	805,206	0.01%	6.75%	0.00%
5.75%	06/15/33	103,092,784	1.57%	5.88%	0.09%
		6,584,418,609	100.00%		4.58%
Adjustment for Tenders and Calls		(521,000)			
Long-Term Debt		$ 6,583,897,609			
Annualized Cost		$ 301,566,372			
Adjustment for Tenders and Calls on Reacquired Debt		68,000			
Total Cost		$ 301,634,372			4.58%

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								
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	3,167,148	296,832,852	98.94%	4.21%
3.70%	09/18/17	09/15/47	30	325,000,000	4,197,845	320,802,155	98.71%	3.77%
3.90%	02/23/18	03/01/48	30	650,000,000	20,205,761	629,794,239	96.89%	4.08%
3.00%	09/10/19	09/15/49	30	325,000,000	6,226,403	318,773,597	98.08%	3.10%
2.80%	06/01/20	06/15/50	30	350,000,000	4,016,000	345,984,000	98.85%	2.86%
3.05%	03/01/21	03/01/51	30	375,000,000	4,623,750	370,376,250	98.77%	3.11%
2.85%	09/14/21	09/15/51	30	375,000,000	3,952,315	371,047,685	98.95%	2.90%
4.60%	05/24/22	05/15/52	30	350,000,000	6,229,966	343,770,034	98.22%	4.71%
4.38%	08/23/22	08/15/52	30	425,000,000	6,205,230	418,794,770	98.54%	4.46%
4.90%	06/23/23	06/15/33	10	575,000,000	6,027,683	568,972,317	98.95%	5.03%
5.46% (3)	09/01/24	09/01/54	30	575,000,000	6,037,500	568,962,500	98.95%	5.53%
5.46% (3)	09/01/25	09/01/55	30	975,000,000	10,237,500	964,762,500	98.95%	5.53%
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%
6.75% (4)	04/06/98	04/06/28	30	805,206	-	805,206	100.00%	6.75%
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.

(3) Estimated.

(4) Variable rate at Prime Rate of 4.75% plus two-percentage points.

Source of Information: Company provided data

Monthly Dividend Yields for
Electric Group
for the Twelve Months Ending December 2023

Company	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	12-Month Average	6-Month Average	3-Month Average
AVANGRID, Inc (AGR)	4.20%	4.51%	4.43%	4.40%	4.69%	4.69%	4.78%	5.10%	5.86%	5.95%	5.70%	5.46%			
Consolidated Edison Inc (ED)	3.42%	3.63%	3.40%	3.31%	3.48%	3.60%	3.44%	3.65%	3.81%	3.72%	3.60%	3.58%			
Dominion Energy, Inc. (D)	4.23%	4.86%	4.79%	4.71%	5.38%	5.18%	5.03%	5.50%	6.01%	6.70%	5.89%	5.71%			
Duke Energy Corporation (DUK)	3.96%	4.27%	4.19%	4.10%	4.51%	4.51%	4.42%	4.63%	4.67%	4.66%	4.45%	4.25%			
Eversource Energy (ES)	3.29%	3.61%	3.46%	3.50%	3.91%	3.82%	3.76%	4.28%	4.65%	5.05%	4.58%	4.38%			
Exelon Corp (EXC)	3.44%	3.57%	3.45%	3.41%	3.64%	3.55%	3.47%	3.60%	3.83%	3.73%	3.75%	4.03%			
FirstEnergy Corp (FE)	3.84%	3.95%	3.92%	3.95%	4.19%	4.04%	4.00%	4.34%	4.60%	4.66%	4.45%	4.50%			
NextEra Energy Inc (NEE)	2.52%	2.63%	2.43%	2.45%	2.55%	2.53%	2.56%	2.80%	3.27%	3.23%	3.20%	3.09%			
PPL Corp (PPL)	3.26%	3.57%	3.46%	3.36%	3.70%	3.64%	3.50%	3.89%	4.09%	3.93%	3.71%	3.55%			
Public Service Enterprise Group Inc (PEG)	3.70%	3.81%	3.66%	3.63%	3.85%	3.65%	3.63%	3.77%	4.02%	3.72%	3.68%	3.74%			
Average	**3.59%**	**3.84%**	**3.72%**	**3.68%**	**3.99%**	**3.92%**	**3.86%**	**4.16%**	**4.48%**	**4.54%**	**4.30%**	**4.23%**	**4.03%**	**4.26%**	**4.36%**

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: https://finance.yahoo.com
https://www.nasdaq.com

Forward-looking Dividend Yield

1/2 Growth	D_0/P_0	(.5g)	D_1/P_0	$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$
	4.26%	1.030000	4.39%	
Discrete	D_0/P_0	Adj.	D_1/P_0	$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$
	4.26%	1.037227	4.42%	
Quarterly	D_0/P_0	Adj.	D_1/P_0	$K = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$
	1.0650%	1.014674	4.39%	
Average			4.40%	
Growth rate			6.00%	
K			10.40%	

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.	7.00%	-	9.00%	-	0.50%	-	3.50%	-
Consol. Edison	1.50%	2.00%	3.00%	2.50%	4.00%	4.00%	4.50%	4.00%
Dominion Energy, Inc.	2.50%	3.00%	0.50%	4.00%	5.50%	4.50%	3.00%	4.00%
Duke Energy	4.50%	3.00%	3.50%	3.00%	1.00%	2.00%	5.00%	4.00%
Eversource Energy	5.50%	6.50%	6.00%	7.50%	4.50%	5.50%	7.50%	5.00%
Exelon Corp.	2.50%	-0.50%	4.00%	-3.00%	3.50%	4.50%	5.50%	3.00%
FirstEnergy Corp.	-1.50%	-	1.50%	-3.50%	-2.50%	-6.50%	-6.50%	-3.00%
NextEra Energy	11.00%	8.00%	12.00%	11.00%	7.50%	8.00%	9.00%	7.50%
PPL Corp.	-11.50%	-6.00%	-2.00%	-	4.00%	-	-5.00%	-3.50%
Public Serv. Enterprise	4.50%	2.00%	4.50%	4.00%	2.00%	4.00%	3.00%	2.00%
Average	2.60%	2.25%	4.20%	3.19%	3.00%	3.25%	2.95%	2.56%

Source of Information: Value Line Investment Survey, November 10, 2023

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

Electric Group	I/B/E/S First Call	Zacks	Value Line Earnings Per Share	Value Line Dividends Per Share	Value Line Book Value Per Share	Value Line Cash Flow Per Share	Value Line Percent Retained to Common Equity
AVANGRID, Inc.	neg.	4.10%	4.50%	1.00%	1.50%	4.00%	1.50%
Consol. Edison	5.66%	2.00%	6.00%	3.50%	3.00%	5.50%	3.50%
Dominion Energy, Inc.	neg.	4.00%	0.50%	1.50%	4.00%	1.00%	3.00%
Duke Energy	6.70%	6.30%	5.00%	2.00%	2.50%	5.00%	3.00%
Eversource Energy	4.00%	5.00%	6.00%	6.00%	4.00%	5.50%	4.00%
Exelon Corp.	4.20%	5.60%	NMF	NMF	NMF	NMF	4.00%
FirstEnergy Corp.	6.30%	NA	4.50%	4.50%	7.50%	3.00%	5.00%
NextEra Energy	8.15%	8.20%	9.50%	9.50%	8.00%	7.50%	5.50%
PPL Corp.	17.21%	7.40%	8.00%	-1.50%	3.50%	3.50%	3.50%
Public Serv. Enterprise	5.20%	4.90%	4.00%	5.50%	2.50%	3.50%	4.50%
Average	7.18%	5.28%	5.33%	3.56%	4.06%	4.28%	3.75%

Source of Information :
Yahoo Finance, January 4, 2024
Zacks, January 4, 2024
Value Line Investment Survey, November 10, 2023

Electric Group
Financial Risk Adjustment

		AVANGRID Inc (AGR)	Consolidated Edison Inc (ED)	Dominion Energy, 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		12/31/22	12/31/22	12/31/22	12/31/22	12/31/22	12/31/22	12/31/22	12/31/22	12/31/22	12/31/22	
Capitalization at Fair Values												
	Debt(D)	7,991,000	18,234,000	38,216,000	63,454,000	18,891,300	32,613,000	19,784,000	57,892,000	12,239,000	16,164,000	28,547,830
	Preferred(P)	0	0	1,783,000	1,962,000	136,700	0	0	0	0	0	388,170
	Equity(E)	16,617,297	31,642,920	51,202,200	79,302,300	29,213,533	42,963,271	23,995,171	166,113,200	21,520,150	30,451,190	49,302,123
	Total	24,608,297	49,876,920	91,201,200	144,718,300	48,241,533	75,576,271	43,779,171	224,005,200	33,759,150	46,615,190	78,238,123
Capital Structure Ratios												
	Debt(D)	32.47%	36.56%	41.90%	43.85%	39.16%	43.15%	45.19%	25.84%	36.25%	34.68%	37.91%
	Preferred(P)	0.00%	0.00%	1.96%	1.36%	0.28%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%
	Equity(E)	67.53%	63.44%	56.14%	54.80%	60.56%	56.85%	54.81%	74.16%	63.75%	65.32%	61.74%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.01%
Common Stock												
	Issued		355,000.000				995,830.000				534,000.000	
	Treasury		23,000.000				2,000.000				37,000.000	
	Outstanding	386,628.586	332,000.000	835,000.000	770,000.000	348,443.855	993,830.000	572,130.932	1,987,000.000	736,487.000	497,000.000	
	Market Price	$42.98	$95.31	$61.32	$102.99	$83.84	$43.23	$41.94	$83.60	$29.22	$61.27	
Capitalization at Carrying Amounts												
	Debt(D)	8,627,000	20,796,000	41,517,000	71,215,000	21,044,100	37,464,000	21,641,000	61,889,000	13,243,000	18,070,000	31,550,610
	Preferred(P)	0	0	1,783,000	1,962,000	155,600	0	0	0	0	0	390,060
	Equity(E)	19,380,000	20,687,000	26,098,000	47,360,000	15,473,158	24,744,000	10,166,000	39,229,000	13,915,000	13,729,000	23,078,116
	Total	28,007,000	41,483,000	69,398,000	120,537,000	36,672,858	62,208,000	31,807,000	101,118,000	27,158,000	31,799,000	55,018,786
Capital Structure Ratios												
	Debt(D)	30.80%	50.13%	59.82%	59.08%	57.38%	60.22%	68.04%	61.20%	48.76%	56.83%	55.23%
	Preferred(P)	0.00%	0.00%	2.57%	1.63%	0.42%	0.00%	0.00%	0.00%	0.00%	0.00%	0.46%
	Equity(E)	69.20%	49.87%	37.61%	39.29%	42.19%	39.78%	31.96%	38.80%	51.24%	43.17%	44.31%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Betas	Value Line	0.85	0.75	0.85	0.85	0.90	NMF	0.85	0.95	1.05	0.90	0.88

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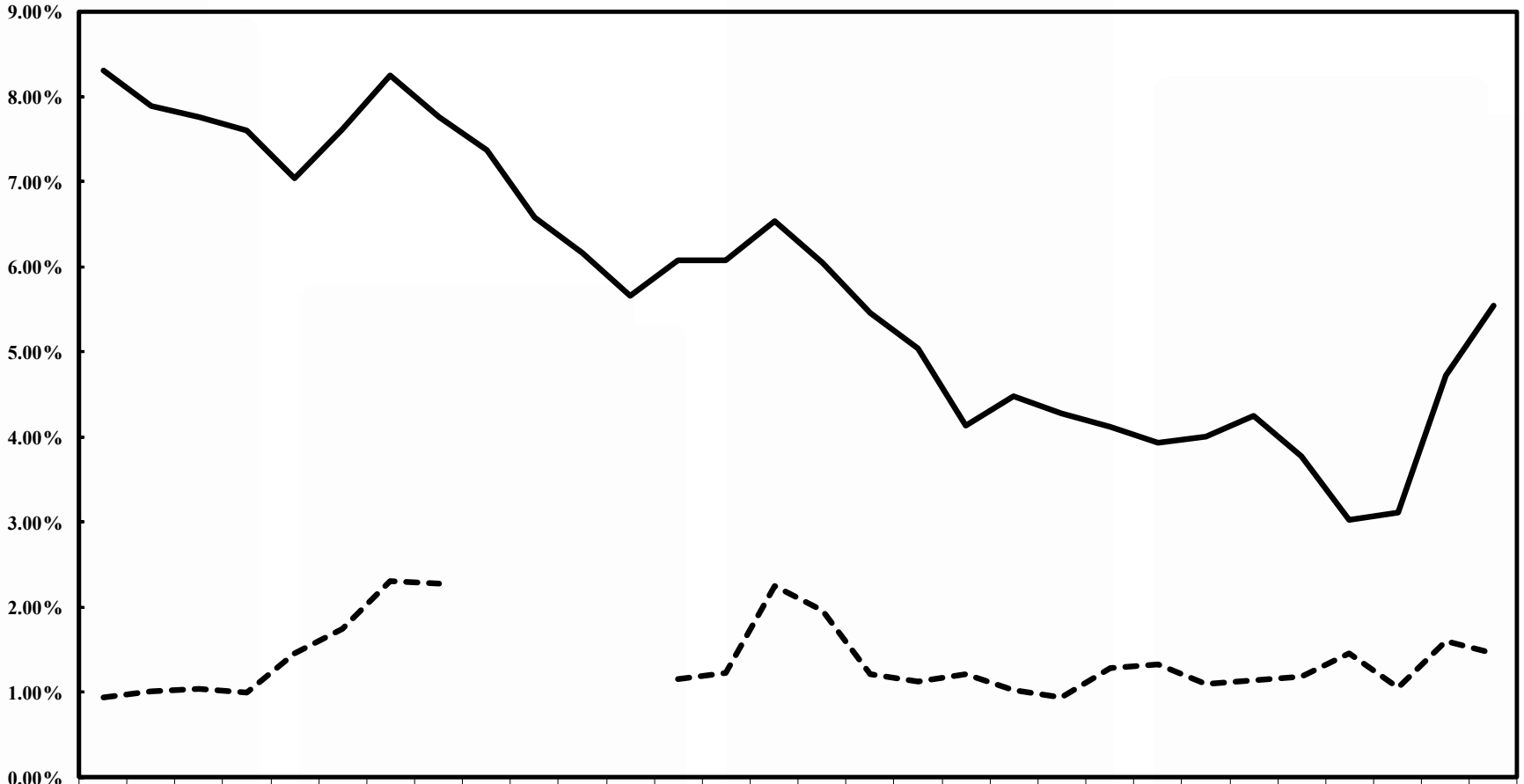
Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2017-2022
and the Twelve Months Ended December 2023

Years	Aa Rated	A Rated	Baa Rated	Average
2018	4.09%	4.25%	4.67%	4.34%
2019	3.61%	3.77%	4.19%	3.86%
2020	2.79%	3.02%	3.39%	3.07%
2021	2.97%	3.11%	3.36%	3.15%
2022	4.53%	4.72%	5.03%	4.77%
Five-Year Average	3.60%	3.77%	4.13%	3.84%
Months				
Jan-23	4.98%	5.20%	5.49%	5.23%
Feb-23	5.12%	5.29%	5.54%	5.32%
Mar-23	5.24%	5.39%	5.68%	5.44%
Apr-23	5.00%	5.13%	5.47%	5.20%
May-23	5.24%	5.36%	5.71%	5.44%
Jun-23	5.26%	5.38%	5.73%	5.46%
Jul-23	5.30%	5.41%	5.73%	5.48%
Aug-23	5.58%	5.71%	6.08%	5.77%
Sep-23	5.72%	5.86%	6.15%	5.91%
Oct-23	6.19%	6.34%	6.61%	6.38%
Nov-23	5.82%	5.96%	6.20%	5.99%
Dec-23	5.27%	5.42%	5.68%	5.46%
Twelve-Month Average	5.39%	5.54%	5.84%	5.59%
Six-Month Average	5.65%	5.78%	6.08%	5.83%
Three-Month Average	5.76%	5.91%	6.16%	5.94%

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	2018	2019	2020	2021	2022	2023
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	4.25	3.77	3.02	3.11	4.72	5.54
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	1.33	1.10	1.14	1.19	1.46	1.06	1.60	1.45

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%		
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%		

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
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%
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%
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%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
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%
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-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%
Jan-18	3.86%	2.88%	0.98%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-19	4.35%	3.04%	1.31%
Feb-19	4.25%	3.02%	1.23%
Mar-19	4.16%	2.98%	1.18%
Apr-19	4.08%	2.94%	1.14%
May-19	3.98%	2.82%	1.16%
Jun-19	3.82%	2.57%	1.25%
Jul-19	3.69%	2.57%	1.12%
Aug-19	3.29%	2.12%	1.17%
Sep-19	3.37%	2.16%	1.21%
Oct-19	3.39%	2.19%	1.20%
Nov-19	3.43%	2.28%	1.15%
Dec-19	3.40%	2.30%	1.10%
Jan-20	3.29%	2.22%	1.07%
Feb-20	3.11%	1.97%	1.14%
Mar-20	3.50%	1.46%	2.04%
Apr-20	3.19%	1.27%	1.92%
May-20	3.14%	1.38%	1.76%
Jun-20	3.07%	1.49%	1.58%
Jul-20	2.74%	1.31%	1.43%
Aug-20	2.73%	1.36%	1.37%
Sep-20	2.84%	1.42%	1.42%
Oct-20	2.95%	1.57%	1.38%
Nov-20	2.85%	1.62%	1.23%
Dec-20	2.77%	1.67%	1.10%
Jan-21	2.91%	1.82%	1.09%
Feb-21	3.09%	2.04%	1.05%
Mar-21	3.44%	2.34%	1.10%
Apr-21	3.30%	2.30%	1.00%
May-21	3.33%	2.32%	1.01%
Jun-21	3.16%	2.16%	1.00%
Jul-21	2.95%	1.94%	1.01%
Aug-21	2.95%	1.92%	1.03%
Sep-21	2.96%	1.94%	1.02%
Oct-21	3.09%	2.06%	1.03%
Nov-21	3.02%	1.94%	1.08%
Dec-21	3.13%	1.85%	1.28%
Jan-22	3.33%	2.10%	1.23%
Feb-22	3.68%	2.25%	1.43%
Mar-22	3.98%	2.41%	1.57%
Apr-22	4.32%	2.81%	1.51%
May-22	4.75%	3.07%	1.68%
Jun-22	4.86%	3.25%	1.61%
Jul-22	4.78%	3.10%	1.68%
Aug-22	4.76%	3.13%	1.63%
Sep-22	5.28%	3.56%	1.72%
Oct-22	5.88%	4.04%	1.84%
Nov-22	5.75%	4.00%	1.75%
Dec-22	5.28%	3.66%	1.62%
Jan-23	5.20%	3.66%	1.54%
Feb-23	5.29%	3.80%	1.49%
Mar-23	5.39%	3.77%	1.62%
Apr-23	5.13%	3.68%	1.45%
May-23	5.36%	3.86%	1.50%
Jun-23	5.38%	3.87%	1.51%
Jul-23	5.41%	3.96%	1.45%
Aug-23	5.71%	4.28%	1.43%
Sep-23	5.86%	4.47%	1.39%
Oct-23	6.34%	4.95%	1.39%
Nov-23	5.96%	4.66%	1.30%
Dec-23	5.42%	4.14%	1.28%

Recent Average:	12-months	1.45%
	6-months	1.37%
	3-months	1.32%

Common Equity Risk Premiums
Years 1926-2022

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	12.40%	5.27%	7.13%	2.83%
Average Across All Interest Rates	12.02%	6.06%	5.96%	4.91%
High Interest Rates	11.63%	6.87%	4.76%	7.03%

Source of Information: 2023 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
2020	18.40%	15.40%	1.37%
2021	28.71%	-2.66%	1.88%
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%
2019	31.49%	19.95%	2.25%
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%
2017	21.83%	12.25%	2.54%
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%
2018	-4.38%	-4.73%	2.84%
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%
2022	-18.11%	-26.18%	4.24%
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 2018-2022
and the Twelve Months Ended December 2023

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2018	2.33%	2.53%	2.63%	2.75%	2.85%	2.91%	3.02%	3.11%
2019	2.05%	1.97%	1.94%	1.96%	2.05%	2.14%	2.40%	2.58%
2020	0.38%	0.40%	0.43%	0.54%	0.73%	0.89%	1.35%	1.56%
2021	0.10%	0.27%	0.46%	0.86%	1.19%	1.44%	1.98%	2.05%
2022	2.79%	2.98%	3.05%	3.00%	3.01%	2.95%	3.30%	3.12%
Five-Year Average	1.53%	1.63%	1.70%	1.82%	1.97%	2.07%	2.41%	2.48%
Months								
Jan-23	4.69%	4.21%	3.91%	3.64%	3.59%	3.53%	3.81%	3.66%
Feb-23	4.93%	4.53%	4.23%	3.94%	3.86%	3.75%	3.95%	3.80%
Mar-23	4.68%	4.30%	4.09%	3.82%	3.77%	3.66%	3.94%	3.77%
Apr-23	4.68%	4.02%	3.76%	3.54%	3.50%	3.46%	3.80%	3.68%
May-23	4.91%	4.13%	3.82%	3.59%	3.58%	3.57%	3.96%	3.86%
Jun-23	5.24%	4.64%	4.27%	3.95%	3.85%	3.75%	4.04%	3.87%
Jul-23	5.37%	4.83%	4.47%	4.14%	4.03%	3.90%	4.15%	3.96%
Aug-23	5.37%	4.90%	4.59%	4.31%	4.26%	4.17%	4.46%	4.28%
Sep-23	5.44%	5.02%	4.74%	4.49%	4.46%	4.38%	4.65%	4.47%
Oct-23	5.42%	5.07%	4.89%	4.77%	4.82%	4.80%	5.13%	4.95%
Nov-23	5.28%	4.88%	4.64%	4.49%	4.53%	4.50%	4.84%	4.66%
Dec-23	4.96%	4.46%	4.19%	4.00%	4.04%	4.02%	4.32%	4.14%
Twelve-Month Average	5.08%	4.58%	4.30%	4.06%	4.02%	3.96%	4.25%	4.09%
Six-Month Average	5.31%	4.86%	4.59%	4.37%	4.36%	4.30%	4.59%	4.41%
Three-Month Average	5.22%	4.80%	4.57%	4.42%	4.46%	4.44%	4.76%	4.58%

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 December 1, 2023 and December 28, 2023

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2024	First	5.0%	4.5%	4.2%	4.2%	4.3%	5.1%	6.1%
2024	Second	4.7%	4.2%	4.0%	4.1%	4.3%	5.0%	6.0%
2024	Third	4.4%	4.0%	3.9%	3.9%	4.2%	4.9%	6.0%
2024	Fourth	4.2%	3.8%	3.8%	3.9%	4.1%	4.8%	5.9%
2025	First	3.9%	3.7%	3.6%	3.8%	4.0%	4.8%	5.8%
2025	Second	3.7%	3.6%	3.6%	3.7%	4.0%	4.7%	5.8%
Long-range CONSENSUS								
2025		3.7%	3.7%	3.7%	3.9%	4.1%	5.0%	6.0%
2026		3.4%	3.5%	3.7%	3.9%	4.1%	4.9%	6.0%
2027		3.3%	3.4%	3.7%	3.9%	4.1%	4.9%	6.0%
2028		3.3%	3.4%	3.7%	3.9%	4.2%	5.0%	6.0%
2029		3.2%	3.4%	3.7%	3.9%	4.2%	5.0%	6.0%
Averages:								
	2025-2029	3.4%	3.5%	3.7%	3.9%	4.1%	4.9%	6.0%
	2030-2034	3.2%	3.4%	3.7%	3.9%	4.2%	5.0%	6.0%

Measures of the Market Premium

Historical Market Premium

Avg. to Low Interest Rates	(Rm)	(Rf)	
1926-2022 Arith. mean	12.21%	3.87%	8.34%

Forecast Market Premium

Value Line	Dividend Yield		Median Appreciation Potential		Median Total Return
As of: 29-Dec-23	2.2%	+	9.73%	=	11.93%
Risk-free Rate of Return (Rf)					3.75%
					8.18%
Average - Historical/Forecast					8.26%

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 2, 3 & 4; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++, A & A+;
Price Stability of 75 to 95; Betas of .75 to 1.05; and Technical Rank of 3 & 4

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
AAON Inc	Machinery	3	3	B+	80	0.85	3
Abbott Laboratories	Med Supp Non-Invasive	3	1	A+	95	0.90	5
AbbVie Inc	Drug	3	2	A	95	0.85	4
Acushnet Holdings	Recreation	2	3	B++	75	0.95	3
Agilent Technologies	Precision Instrument	3	2	A	90	0.95	3
Allstate Corporation	Insurance (Prop/Cas.)	2	2	A	90	1.00	5
Altria Group Inc	Tobacco	3	3	B++	95	0.85	3
Amphenol Corp	Electronics	3	1	A	95	1.05	3
Analog Devices Inc	Semiconductor	3	1	A+	85	1.00	3
Arthur J Gallagher and Company	Financial Svcs. (Div.)	4	1	A	95	0.95	4
Booz Allen Hamilton Holding Corporati	Industrial Services	3	2	B++	90	0.85	3
Boston Scientific Corp	Med Supp Invasive	4	3	B++	85	1.05	4
Brady Corp	Diversified Co.	3	2	B++	90	0.95	4
Broadridge Fin'l	Information Services	3	2	B++	95	0.90	3
Brown and Brown Inc	Financial Svcs. (Div.)	3	1	A	95	0.95	3
BWX Technologies	Power	4	2	B++	90	0.80	3
CACI International Inc	IT Services	2	3	B+	90	0.90	4
Caseys General Stores Inc	Retail/Wholesale Food	2	2	B++	90	0.90	3
Cboe Global Markets	Brokers & Exchanges	3	2	A	95	0.80	3
CME Group Inc	Brokers & Exchanges	2	2	A	90	0.95	3
Cognizant Technology Solutions Corp	IT Services	3	2	A+	85	1.00	3
Commerce Bancshares Inc	Bank (Midwest)	3	3	B++	90	0.90	4
Cooper Companies Inc	Med Supp Non-Invasive	3	2	A	80	1.05	3
Copart Inc	Retail Automotive	4	2	B++	85	1.05	3
Corteva Inc.	Chemical (Basic)	4	3	B++	80	0.95	3
CSG Systems International Inc	IT Services	3	2	B+	95	0.75	3
CSW Industrials	Petroleum (Producing)	3	2	B++	85	0.90	3
CSX Corporation	Railroad	3	2	B++	90	1.00	3
Donaldson Co	Machinery	2	2	A	90	1.05	3
EBay Inc	Internet	2	3	B+	75	1.05	3
Expeditors International of Washington	Industrial Services	3	1	A+	95	0.95	3
Exponent Inc.	Information Services	4	3	B+	80	0.95	4
F5 Inc.	Telecom. Equipment	2	2	A	75	0.95	3
Fastenal Co	Retail Building Supply	2	1	A+	95	0.90	3
FirstCash Holdings	Financial Svcs. (Div.)	2	3	B++	80	0.90	4
Fiserv Inc	IT Services	2	2	B++	85	1.05	4
Franklin Electric Co Inc	Electrical Equipment	3	2	A	90	0.90	3
GATX Corp	Railroad	3	3	B+	90	0.95	3
Gen Digital Inc.	Cyber Security	2	3	B+	75	0.80	3
Graco Inc	Machinery	2	2	A	90	1.05	3
Graphic Packaging	Packaging & Container	3	3	B+	85	1.05	3
Hanover Insurance Group Inc	Insurance (Prop/Cas.)	4	2	A	95	0.95	5
Harris Corp.	Aerospace/Defense	3	2	A+	85	0.90	3
Henry Schein Inc	Med Supp Non-Invasive	2	3	B+	80	1.00	4
Hologic Inc	Med Supp Non-Invasive	3	3	B+	75	0.95	5
Houlihan Lokey	Investment Banking	4	3	A	90	0.75	3
Huntington Ingalls Industries Inc	Aerospace/Defense	2	3	A	80	0.95	3
Ingredion Incorporated	Food Processing	2	2	B++	95	0.90	3
Intercontinental Exch.	Brokers & Exchanges	4	1	A	95	0.95	3
International Business Machines Corp	Computers/Peripherals	3	3	B++	95	0.90	3
International Paper Co	Paper/Forest Products	3	3	B++	75	1.05	3
J and J Snack Foods Corp	Food Processing	3	2	A	85	0.90	3
Jack Henry and Associates Inc	IT Services	3	1	A+	90	0.85	5
Keysight Technologies	Precision Instrument	3	2	A	75	0.90	3
Knight-Swift Trans.	Trucking	4	3	B++	85	0.85	3
Kraft Heinz Co.	Food Processing	3	3	A	75	0.75	4
Landstar System	Trucking	4	1	A	95	0.80	3
Leidos Holdings Inc	Industrial Services	2	3	B++	75	1.05	4
Lincoln Electric Holdings Inc	Machinery	3	2	A	90	1.00	3
Lindsay Corporation	Machinery	4	3	B++	75	0.90	4
McCormick and Co	Food Processing	4	1	A+	95	0.80	3
Mercury General Corp	Insurance (Prop/Cas.)	2	3	B+	75	0.90	3
Mettler Toledo International Inc	Precision Instrument	3	3	B++	80	1.05	4
Motorola Solutions Inc	Telecom. Equipment	3	2	B++	95	0.95	3
MSCI Inc	Information Services	3	3	B+	75	1.05	3
Murphy USA Inc	Retail (Hardlines)	2	3	B++	75	0.75	3
Nasdaq Inc.	Brokers & Exchanges	3	1	A+	85	1.05	4
NetScout Systems	Cyber Security	3	3	B++	75	0.90	3
Norfolk Southern Corp	Railroad	4	2	A+	85	1.05	3
O Reilly Automotive Inc	Retail Automotive	2	2	B++	90	0.90	3
Omnicom Group Inc	Advertising	3	3	B+	85	1.05	3
Packaging Corp	Packaging & Container	3	2	A	90	0.95	3
Parsons Corp.	Aerospace/Defense	3	3	B++	80	0.95	3
Pfizer Inc	Drug	3	2	A	90	0.80	5
Philip Morris International Inc	Tobacco	4	3	B++	90	0.95	3
Prestige Consumer	Household Products	4	3	B++	90	0.85	3
Quest Diagnostics Inc	Medical Services	3	2	B++	90	0.75	3
RLI Corp	Insurance (Prop/Cas.)	3	2	A	95	0.80	5
RTX Corp.	Aerospace/Defense	2	1	A+	90	1.05	5
S&P Global	Information Services	3	2	A	90	1.05	3
Schneider National	Trucking	4	3	B++	85	0.80	4
Selective Insurance Group Inc	Insurance (Prop/Cas.)	2	3	B++	95	0.85	5
Sensient Technologies Corp	Food Processing	4	3	B++	95	0.90	3
Service Corp International Inc	Industrial Services	3	3	B+	85	0.90	4
Sherwin Williams	Retail Building Supply	2	1	A+	90	0.95	3
Snap on Inc	Machinery	3	2	A+	85	1.05	3
Sonoco Products	Packaging & Container	2	2	A	95	1.00	5
Standard Motor Products Inc	Auto Parts	3	3	B+	75	0.85	3
Stepan Company	Chemical (Specialty)	4	2	B++	85	0.80	3
The Travelers Companies Inc	Insurance (Prop/Cas.)	2	1	A+	95	0.95	4
Thermo Fisher Scientific Inc	Precision Instrument	3	1	A	95	0.85	4
Toro Co	Machinery	2	2	B++	80	1.00	4
Tractor Supply Co	Retail Building Supply	3	2	A+	85	0.75	5
Transmission Holdings Inc	Auto Parts	2	3	B+	80	1.05	3
Trimas Corporation	Diversified Co.	3	3	B+	80	0.90	4
Tyler Technologies	IT Services	4	2	A+	85	0.85	3
UniFirst Corp	Industrial Services	3	2	A	90	0.90	3
United Parcel Service	Air Transport	4	2	A+	85	0.80	4
Vail Resorts	Hotel/Gaming	4	3	B+	75	1.05	4
Valmont Industries	Diversified Co.	4	2	A	75	1.05	4
Verisk Analytics Inc	Information Services	2	2	B++	95	0.90	3
Walt Disney Co	Entertainment	4	2	A	80	1.05	5
Waters Corp	Precision Instrument	2	2	A	85	0.95	3
Werner Enterprises Inc	Trucking	4	2	B++	95	0.75	4
Western Union Company	Financial Svcs. (Div.)	2	3	B+	85	0.85	4
WR Berkley Corp	Insurance (Prop/Cas.)	2	2	B++	85	1.05	4
WW Grainger Inc	Electrical Equipment	3	1	A+	90	1.00	3
Average		3	2	B++	87	0.93	3
Electric Group	Average	3	2	A	87	0.88	4

Source of Information: Value Line Investment Survey for Windows, January 2024

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2018-2022 and
Projected 3-5 Year Returns

Company	2018	2019	2020	2021	2022	Average	Projected 2026-28
AAON Inc	17.2%	18.5%	21.3%	12.6%	17.9%	17.5%	18.0%
Abbott Laboratories	16.8%	18.7%	20.0%	26.2%	25.8%	21.5%	24.0%
AbbVie Inc	-	-	NMF	NMF	NMF	-	NMF
Acushnet Holdings	11.2%	13.2%	9.8%	17.2%	21.2%	14.5%	22.0%
Agilent Technologies	19.9%	20.8%	21.0%	24.7%	29.5%	23.2%	33.0%
Allstate Corporation	13.9%	12.8%	15.9%	16.5%	NMF	14.8%	13.0%
Altria Group Inc	51.0%	NMF	NMF	NMF	NMF	51.0%	NMF
Amphenol Corp	30.0%	25.5%	22.3%	24.9%	27.1%	26.0%	23.0%
Analog Devices Inc	20.4%	16.3%	15.2%	6.8%	13.6%	14.5%	15.5%
Arthur J Gallagher and Company	13.9%	12.8%	13.2%	10.7%	8.9%	11.9%	18.0%
Booz Allen Hamilton Holding Corporation	58.8%	56.4%	50.8%	54.5%	61.3%	56.4%	33.5%
Boston Scientific Corp	23.6%	16.1%	9.2%	14.4%	14.3%	15.5%	17.0%
Brady Corp	14.9%	15.4%	13.0%	13.5%	16.5%	14.7%	18.0%
Broadridge Fin'l	46.1%	49.1%	43.7%	36.8%	39.9%	43.1%	35.0%
Brown and Brown Inc	11.5%	11.9%	12.8%	14.0%	14.6%	13.0%	16.5%
BWX Technologies	96.3%	60.4%	45.1%	48.0%	31.8%	56.3%	32.5%
CACI International Inc	9.4%	11.2%	12.1%	17.2%	12.0%	12.4%	9.5%
Caseys General Stores Inc	14.5%	16.1%	16.2%	15.2%	16.8%	15.8%	15.5%
Cboe Global Markets	13.1%	11.1%	13.9%	14.6%	6.8%	11.9%	12.5%
CME Group Inc	7.6%	8.1%	8.0%	9.6%	10.0%	8.7%	9.5%
Cognizant Technology Solutions Corp	23.4%	20.3%	17.0%	18.1%	18.6%	19.5%	18.5%
Commerce Bancshares Inc	14.8%	13.4%	10.4%	15.4%	19.8%	14.8%	14.5%
Cooper Companies Inc	10.3%	12.9%	6.2%	9.5%	8.6%	9.5%	9.0%
Copart Inc	26.3%	30.1%	24.5%	25.2%	23.3%	25.9%	20.5%
Corteva Inc.	-	4.4%	4.5%	6.3%	7.6%	5.7%	10.0%
CSG Systems International Inc	18.3%	20.9%	13.9%	16.6%	12.4%	16.4%	22.5%
CSW Industrials	17.5%	16.6%	9.8%	14.2%	18.3%	15.3%	17.0%
CSX Corporation	26.3%	28.1%	21.1%	26.1%	32.4%	26.8%	19.5%
Donaldson Co	31.0%	29.9%	26.0%	25.2%	29.4%	28.3%	19.5%
EBay Inc	40.2%	62.4%	71.4%	17.4%	32.1%	44.7%	33.5%
Expeditors International of Washington Inc	31.1%	26.9%	26.2%	40.5%	43.6%	33.7%	27.5%
Exponent Inc.	23.0%	23.5%	22.8%	24.3%	31.9%	25.1%	28.0%
F5 Inc.	35.3%	24.3%	13.8%	14.0%	13.0%	20.1%	16.0%
Fastenal Co	32.7%	29.7%	31.4%	30.4%	34.4%	31.7%	37.5%
FirstCash Holdings	11.6%	12.2%	8.3%	6.9%	13.5%	10.5%	11.5%
Fiserv Inc	55.9%	8.4%	9.3%	12.1%	13.6%	19.9%	12.5%
Franklin Electric Co Inc	14.6%	12.3%	12.1%	16.3%	17.5%	14.6%	20.0%
GATX Corp	11.2%	10.9%	6.5%	9.0%	10.7%	9.7%	9.5%
Gen Digital Inc.	18.3%	NMF	-	NMF	51.0%	34.7%	27.5%
Graco Inc	43.6%	31.7%	25.7%	25.7%	24.8%	30.3%	19.5%
Graphic Packaging	11.9%	13.2%	11.7%	10.8%	24.3%	14.4%	21.0%
Hanover Insurance Group Inc	9.9%	11.4%	11.1%	11.2%	8.5%	10.4%	28.0%
Harris Corp.	-	3.6%	5.4%	9.6%	5.7%	6.1%	17.0%
Henry Schein Inc	18.1%	23.4%	12.0%	18.4%	15.6%	17.5%	17.0%
Hologic Inc	25.3%	22.8%	29.7%	44.4%	26.7%	29.8%	13.5%
Houlihan Lokey	17.9%	18.7%	22.6%	30.3%	16.0%	21.1%	24.0%
Huntington Ingalls Industries Inc	55.1%	36.5%	36.6%	19.4%	16.6%	32.8%	17.0%
Ingredion Incorporated	20.8%	16.4%	13.6%	14.4%	15.6%	16.2%	20.5%
Intercontinental Exch.	12.1%	12.7%	12.8%	12.8%	13.1%	12.7%	11.5%
International Business Machines Corp	75.4%	54.9%	37.7%	47.7%	37.9%	50.7%	35.0%
International Paper Co	22.3%	15.9%	10.8%	12.4%	17.7%	15.8%	12.5%
J and J Snack Foods Corp	11.1%	11.4%	2.3%	6.6%	5.5%	7.4%	12.0%
Jack Henry and Associates Inc	22.3%	19.0%	19.1%	23.6%	26.3%	22.1%	23.5%
Keysight Technologies	25.4%	30.0%	27.8%	30.8%	33.4%	29.5%	23.5%
Knight-Swift Trans.	8.4%	6.6%	8.0%	12.1%	11.8%	9.4%	7.5%
Kraft Heinz Co.	8.3%	6.8%	7.1%	7.3%	7.1%	7.3%	8.5%
Landstar System	37.2%	31.6%	27.8%	44.3%	48.6%	37.9%	20.5%
Leidos Holdings Inc	20.3%	22.0%	21.8%	22.0%	21.2%	21.5%	20.5%
Lincoln Electric Holdings Inc	35.7%	35.8%	31.6%	43.2%	46.9%	38.6%	22.0%
Lindsay Corporation	11.4%	5.8%	12.9%	12.6%	16.6%	11.9%	13.0%
McCormick and Co	20.9%	20.8%	19.4%	18.7%	14.6%	18.9%	16.0%
Mercury General Corp	6.2%	8.0%	15.1%	7.5%	-	9.2%	26.5%
Mettler Toledo International Inc	83.6%	NMF	NMF	NMF	NMF	83.6%	NMF
Motorola Solutions Inc	-	-	-	-	-	-	NMF
MSCI Inc	-	-	-	-	-	-	NMF
Murphy USA Inc	22.1%	19.3%	49.2%	49.2%	105.0%	49.0%	42.5%
Nasdaq Inc.	14.9%	14.8%	16.0%	19.9%	21.5%	17.4%	15.5%
NetScout Systems	NMF	NMF	1.0%	1.7%	2.9%	1.9%	4.0%
Norfolk Southern Corp	17.4%	17.9%	16.0%	22.0%	25.7	18.3%	23.5%
O Reilly Automotive Inc	NMF	NMF	NMF	NMF	NMF	-	NMF
Omnicom Group Inc	52.1%	46.9%	30.7%	43.0%	40.5%	42.6%	28.0%
Packaging Corp	27.6%	22.7%	16.9%	24.8%	28.4%	24.1%	25.0%
Parsons Corp.	24.5%	7.4%	5.4%	3.4%	4.7%	9.1%	13.5%
Pfizer Inc	17.6%	25.8%	11.0%	29.0%	32.8%	23.2%	22.5%
Philip Morris International Inc	-	-	-	-	-	-	NMF
Prestige Consumer	13.3%	12.2%	12.1%	13.0%	14.5%	13.0%	10.0%
Quest Diagnostics Inc	16.8%	15.9%	22.6%	28.4%	20.0%	20.7%	17.5%
RLI Corp	11.4%	11.8%	10.4%	14.5%	19.1%	13.4%	14.0%
RTX Corp.	16.0%	17.1%	4.6%	8.8%	9.8%	11.3%	13.0%
S&P Global	NMF	NMF	NMF	NMF	10.3%	10.3%	13.5%
Schneider National	12.6%	6.6%	10.3%	16.7%	16.1%	12.5%	12.0%
Selective Insurance Group Inc	12.2%	12.0%	9.1%	13.5%	13.0%	12.0%	21.0%
Sensient Technologies Corp	18.3%	14.2%	11.7%	14.1%	13.9%	14.4%	12.5%
Service Corp International Inc	20.4%	19.4%	29.8%	40.7%	36.3%	29.3%	29.0%
Sherwin Williams	47.1%	47.9%	62.6%	89.3%	74.1%	64.2%	NMF
Snap on Inc	21.9%	20.3%	16.4%	19.6%	20.3%	19.7%	23.5%
Sonoco Products	19.4%	19.8%	18.2%	19.4%	22.6%	19.9%	17.0%
Standard Motor Products Inc	12.2%	13.7%	14.6%	16.2%	12.0%	13.7%	12.0%
Stepan Company	14.4%	11.6%	12.9%	12.8%	12.6%	12.9%	8.5%
The Travelers Companies Inc	10.7%	9.8%	9.2%	12.2%	13.9%	11.2%	11.5%
Thermo Fisher Scientific Inc	10.7%	11.5%	18.5%	18.9%	15.8%	15.1%	15.5%
Toro Co	40.7%	31.9%	29.6%	35.6%	32.8%	34.1%	41.0%
Tractor Supply Co	34.1%	36.0%	41.9%	49.8%	53.3%	43.0%	53.5%
Transmission Holdings Inc	97.0%	77.3%	39.6%	69.7%	60.8%	68.9%	26.0%
Trimas Corporation	13.1%	9.5%	11.8%	9.1%	10.2%	10.7%	11.5%
Tyler Technologies	14.6%	13.1%	11.5%	12.8%	12.1%	12.8%	15.5%
UniFirst Corp	10.2%	10.0%	7.8%	8.1%	5.4%	8.3%	8.5%
United Parcel Service	NMF	NMF	NMF	NMF	57.0%	57.0%	43.0%
Vail Resorts	23.9%	20.1%	7.5%	8.0%	21.6%	16.2%	27.0%
Valmont Industries	16.1%	13.8%	14.8%	16.9%	18.2%	16.0%	16.5%
Verisk Analytics Inc	28.9%	19.9%	26.4%	23.7%	45.5%	28.9%	NMF
Walt Disney Co	25.8%	11.7%	NMF	2.3%	3.4%	10.8%	9.5%
Waters Corp	39.9%	-	NMF	NMF	NMF	39.9%	47.0%
Werner Enterprises Inc	13.6%	15.0%	15.1%	17.6%	16.5%	15.6%	10.5%
Western Union Company	-	-	NMF	NMF	NMF	-	NMF
WR Berkley Corp	9.5%	9.6%	7.1%	14.3%	18.1%	11.7%	4.0%
WW Grainger Inc	49.6%	51.6%	47.9%	55.7%	63.4%	53.6%	47.5%
Average						22.9%	20.0%
Median						16.4%	17.5%
Average (excluding companies with values >20%)						13.1%	13.4%

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. 5-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2024-3046931

REBUTTAL TESTIMONY

WITNESS: PAUL R. MOUL

SUBJECT: OVERALL RATE OF RETURN, INCLUDING CAPITAL STRUCTURE RATIOS, EMBEDDED COST OF DEBT AND THE COST OF EQUITY, FOR PECO ENERGY COMPANY - ELECTRIC DIVISION

DATED: July 16, 2024

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DIRECT TESTIMONY

OF

PAUL R. MOUL

I. INTRODUCTION

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.

2. Q. Did you previously submit testimony in this proceeding on behalf of the Electric Division of PECO Energy Company ("PECO" or the "Company")?

A. Yes. I submitted my direct testimony, PECO Energy Statement No. 5, on March 28, 2024.

3. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony submitted by David J. Garrett, a witness appearing on behalf of the Office of Consumer Advocate ("OCA"), and D.C. Patel, a witness appearing on behalf of the Bureau of Investigation and Enforcement ("I&E"). If I fail to address each and every issue in the testimony of Messrs. Garrett and Patel, it does not imply agreement with those issues. I also comment on certain aspects of the testimony of Walmart witness Lisa Perry and OCA witnesses John Defever, Clarence Johnson and Roger Colton.

4. Q. What are the key aspects of the rate of return issue that the Pennsylvania Public Utility Commission ("Commission") should consider when deciding this issue in this case?

A. The primary issue involves the Company's cost of equity. Mr. Patel has accepted the Company's proposed capital structure ratios. Mr. Garrett has opposed the actual PECO capital structure, and instead proposed a hypothetical capital structure. The cost of debt is not an issue in this case. In each instance, the equity returns proposed by the opposing witnesses are entirely too low to reflect the risks of PECO and the prospective cost of equity. Aside from technical issues that I will discuss later in my rebuttal testimony, the Commission should take into consideration a rate of return that will reflect and be supportive of the Company's financial and risk profile. As I explain below, the opposing party recommendations fail to adequately consider this point and thereby significantly understate the required cost of common equity in this proceeding.

5. Q. Please summarize the key points of your rebuttal testimony.

A. My key points are:

- Capital Structure Ratios – Mr. Garrett's use of a hypothetical capital structure, rather than the Company's projected actual capital structure for the FPFTY, is improper and contrary to standard practice in Pennsylvania.
- Comparable Companies – Mr. Patel makes an unnecessary exclusion and needless additions of companies, which results in a barometer group that is less comparable in this case.

- Discounted Cash Flow ("DCF") – The DCF results presented by Mr. Garrett and Mr. Patel are clearly too low to provide a reliable measure of the cost of equity. This can be traced to the formulaic approach taken by Mr. Patel in applying this model (see pages 27-28 of I&E Statement No. 2). In addition, Mr. Garrett fails to adequately reflect investor expectations of growth that are specific to the electric utilities included in his proxy group. He errs when using analysts' growth rate forecasts by failing to consider earnings per share growth that is used by Mr. Patel, me, and the Commission.
- The DCF growth rate proposed by Mr. Garrett in his "sustainable growth rate" form is not reflective of the type of growth expected by investors in these companies. Rather, it is a generic growth rate that would apply to any or all companies, including disparate companies, such as Microsoft Corporation, Tesla, Inc. or any other regulated or non-regulated company.
- Leverage Adjustment – The I&E and OCA witnesses have not refuted the accuracy of my leverage adjustments to the DCF and beta component of the Capital Asset Pricing Model ("CAPM").
- CAPM – A reasonable application of the CAPM mandates using 30-year Treasury bond yield and leverage adjusted betas indicates an equity cost rate that is 11.02% in this case when setting aside the leverage adjustment. Even Mr. Patel's CAPM results in an 11.29% return, demonstrating that the DCF results of Mr. Garrett are inadequate, particularly in light of the Commission's recent determination of the equity cost rate of 10.00% for

Aqua Pennsylvania on a 53.95% common equity ratio and 9.75% for Columbia Water on a 63.34% common equity ratio.

- Additional methods should also be considered when establishing the cost of equity for PECO.

6. Q. How should the rate of return set by the Commission support the Company's financial profile?

A. The Commission should set the Company's return on equity at a level that will attract investment in the Company to ensure the Company's financial ability to render safe and reliable service. Applying this principle, the Commission should reject the proposals by Messrs. Garrett and Patel to impose a return on common equity of 9.20% and 9.91%, respectively. These proposed returns are unreasonable because they are much too low to allow PECO to achieve the level of returns that meet investor expectations. Equity returns of this magnitude would be viewed by investors as unsupportive of the Company's financial condition. Rather, based on the factors listed below, and for technical reasons set forth later in my rebuttal testimony, the Commission should adopt a substantially higher equity return for PECO.

7. Q. Are there additional issues that the Commission should consider when setting the Company's return?

A. Yes. The investment community would be very concerned if the Commission were to adopt either of the positions of the I&E or OCA. If it were to do so, investors would see Pennsylvania regulation as less supportive of the Company at a time of high levels of capital investment. If the Commission were to follow the proposals of I&E or the OCA, the regulatory ranking of Pennsylvania would

certainly be jeopardized. The return on equity used by the Commission to set rates embodies in a single numerical value a clear signal of regulatory support for the financial strength of the utilities that it regulates. Although cost allocations, rate design issues, and regulatory policies relative to the cost of service are important considerations, the opportunity to achieve a reasonable return on equity represents a direct signal to the investment community of regulatory support (or lack thereof) for the utility's financial strength. In a single figure, the return on equity utilized to set rates provides a common and widely understood benchmark that can be compared from one company to another and is the basis by which returns on all financial assets (stocks – both utility and non-regulated, bonds, money market instruments, and so forth) can be measured. So, while varying degrees of sophistication are required to interpret the meaning of specific Commission policies on technical matters, the return on equity figure is universally understood and communicates to investors the types of returns that they can reasonably expect from an investment in utilities operating in Pennsylvania.

8. Q. How do the cost of equity proposals by Mr. Garrett and Mr. Patel compare to the utility returns recently authorized by the Commission?

A. Technical disputes about methodology and data aside, the proposed costs of equity proposed by Mr. Garrett and Mr. Patel are simply not representative of the return investors can earn on other investments of comparable risk, including investments in other electric utilities, such as PECO. Indeed, the Commission established a 9.85% equity return for the UGI Utilities Electric Division rate case at Docket No. R-2017-2640058. With rising capital cost rates, a higher, not

lower, equity return is required in this case. The Commission also granted equity returns of 9.54% for Citizens' Electric Company at Docket No. R-2019-3008212, 9.31% for Wellsboro Electric Company at Docket No. R-2019-3008208, 9.73% for Valley Energy at Docket No. R-2019-3008209, 9.86% for Columbia Gas of Pennsylvania at Docket No. R-2020-3018835, 10.8% for Pennsylvania-American Water Company at Docket Nos. R-2020-3019369 and R-2020-3019371,[1] and later a 10.24% equity return was provided to PECO Energy Company – Gas Division at Docket No. R-2020-3018929. Subsequently, the Commission granted Aqua Pennsylvania a 10.00% return on equity at Docket No. R-2021-3027385 and 9.75% to Columbia Water Company at docket No. R-2023-3040258. Moreover, for purposes of setting the Distribution System Improvement Charge ("DSIC"), the Commission has set a 9.75% equity return for electric utilities. In the DSIC proceedings, DSIC recoveries are reconciled and therefore the 9.75% is guaranteed. In contrast, the equity return set in a base rate case is an opportunity to earn an allowed equity return and should be higher than the DSIC equity allowance.

The rates of return on common equity of 9.20% proposed by Mr. Garrett and 9.91% proposed by Mr. Patel are seriously deficient and will not provide PECO with the opportunity to earn its investor required cost of capital for the fully projected future test year ending December 31, 2025 ("FPFTY"). As explained below, this is not the time for the Commission to be reducing the Company's

[1] The Commission's Opinion and Order in this case held that: "We agree with the ALJ's rationale and recommendation on this issue, approving, as contained within the Joint Settlement, the Company's application of traditional ROE models and its analysis of current market conditions." *Pa. PUC, et al. v. Pennsylvania-American Water Company*, Docket Nos. R-2020-3019369 (Water), R-2020-3019371 (Wastewater), at 62 (Opinion and Order entered Feb. 25, 2021).

authorized return when there is a compelling need for capital investment to rehabilitate aging infrastructures.

9. Q. Should the commission consider the current high level of capital costs when deciding the return on equity in this case?

A. Yes. The Commission should recognize that accommodative policy by the Federal Reserve's Open Market Committee (the "FOMC") has ended and higher interest rates have occurred and will prevail in the future. High inflation also has been a driving factor. As noted previously, the rate of inflation spiked upward to 9.1% in June 2022, and as of May 2024, it stood at 3.3%. High levels of inflation have an impact on the level of economic activity, the cost of capital – particularly the interest cost of debt – and the need for more cautious financial practices, such as a prudent level of borrowing. Today's inflation continues to be higher than the target rate of 2%, which is the FOMC policy goal.

One reason that explains the higher long-term interest rates can be traced to investor expectations of high inflation noted above. Higher interest rates clearly point to higher capital costs prospectively. The yield on 30-year Treasury bonds moved above the 2% level beginning in February 2021. In comparison, those yields closed out 2020 at 1.67% for December. By May 2024, the yield on 30-year Treasury bonds had moved to 4.62%, or an increase of 2.95% (or 177%). Likewise, the yield on A-rated public utility bonds has increased to 5.74% in May 2024 up from 2.77% in December 2020 – a 297 basis point (or 107%) increase. I will describe the Blue Chip forecast of interest rates and the continuation of this trend below. Indeed, the reality of high interest rates demands higher, not lower capital costs.

10. Q. Is there additional evidence that suggests that the cost of capital will continue at high levels?

A. Yes. To gain a consensus view of future interest rates, I tabulated the forecasts of yields on 10-year Treasury notes published by a variety of well-recognized and investor-influencing sources. I chose the 10-year Treasury note because it is available on a justification has changed consistent basis for each source. The comparisons are:

	2025	2026	207	2028	2029	2030
Blue Chip	4.0%	4.0%	4.0%	4.0%	4.2%	4.2%
CBO	4.1%	3.7%	3.6%	3.7%	3.8%	3.9%

The Blue Chip (June 1, 2024) and CBO (June 2024) reflect that the general consensus is that interest rates will remain at elevated levels in the future. The high levels of interest rates represent one key factor that adds to the risk of common equity. And for comparison purposes, the yield on public utility bonds always exceeds Treasury yields. As noted in my direct testimony (see page 40 of PECO Statement No. 5), the spread in those yields is at least 1.25%, and historically higher than that through most of the year 2023. Page 2 of Schedule 11 shows a spread of 1.45% on average for 2023. The Commission should take into account the forecast of interest rates when it sets the cost of equity for PECO.

11. Q. At page 24 of Statement No. 2, Mr. Patel indicated that he believes that the FOMC intends to cut rates in the future. Should Commission take this possibility into account when setting a cost of equity in this proceeding?

A. Not at this time. There is always the possibility that the Fed Funds rate could be cut by the FOMC. But there also is the possibility that the rate could be increased at some point in the future. To add perspective, there was considerable discussion early in 2024 that the FOMC might cut the Fed Funds rate six times in 2024. We are now halfway through 2024 and the Fed Funds rate remains unchanged. A variety of factors influence the FOMC, such as the condition of the economy, the health of the labor markets, and other factors. With no definitive plan in place, it would be speculative to infer what might occur in the future regarding the Fed Funds rate.

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

A. I will cover the issues of (i) capital structure, (ii) the composition of the proxy (i.e., barometer) group, (iii) the weight to be given to the DCF method, (iv) the DCF growth rate, (v) the leverage adjustment to the DCF and CAPM methods, (vi) the CAPM method, (vii) the Risk Premium analysis, (viii) Comparable Earnings, and (ix) management performance as part of the return on equity consideration.

II. CAPITAL STRUCTURE

13. Q. Is there a difference in the proposed capital structure ratios utilized by the justification changed rate of return witnesses in this case?

A. Yes. Mr. Garrett is alone in advocating an erroneous capital structure for PECO. Mr. Patel has accepted the Company's proposed capital structure, as it falls within the range of capital structures of both his expanded proxy group and the proxy group Mr. Garrett and I have used. Mr. Garrett's position is clearly contrary to long-standing Commission policy concerning capital structure ratios,

most recently confirmed in Columbia Water Company at Docket No. R-2023-3040258, and previously in Aqua Pennsylvania, Inc. at Docket No. R-2021-3027385, and in the PECO Energy Company – Gas Division rate case at Docket No. R-2020-3018929.

14. Q. What capital structure does Mr. Garrett propose?

A. Mr. Garrett has proposed a hypothetical capital structure for PECO without ever demonstrating that the Company's proposed capital structure is unreasonable. Rather, his proposed capital structure is simply designed to lower the Company's revenue requirement. In reaching his conclusion on capital structure ratios, Mr. Garrett performed three analyses. These are (i) a calculation of the cost of capital at various debt ratios, (ii) the debt ratios of the companies in his proxy group, and (iii) the debt ratios of thousands of other companies. He seems to favor option (ii), but does not propose a debt ratio as high as he reports for his proxy group. This approach essentially advocates the use of a hypothetical capital structure that violates Commission precedent on the use of the actual capital structure. If he had considered other rate cases decided by the Commission as guides for the selection of capital structure ratios, then he should have relied upon PECO's actual capital structure ratios.

15. Q. Is there any basis to deviate from the Company's actual capital structure to set the rate of return in this case?

A. No. First, as Mr. Patel explained (see pages 11-13 of I&E Statement No. 2), the Company's actual capital structure ratio (including the 53.40% common equity ratio) falls within the range of the proxy group. This is sufficient to meet the

Commission standard that the use of actual PECO capital structure is appropriate in this case.

Second, Mr. Garrett might also have been led to a different conclusion if he had considered the common equity ratios utilized by this Commission in recent rate case decisions. Indeed, in its Order Entered on October 25, 2018, in Docket No. R-2017-2640058, the Commission adopted a 54.02% common equity ratio for the Electric Division of UGI Utilities. Furthermore, the Commission accepted a 54.19% common equity ratio in the Columbia Gas of Pennsylvania rate case at Docket No. R-2020-3018835 (Order Entered February 19, 2021) and 53.38% common equity ratio for PECO Energy Company – Gas Division at Docket No. R-2020-3018929 (Order Entered June 22, 2021). And in the Aqua Pennsylvania case, the Commission accepted a 53.95% common equity ratio and for Columbia Water Company a 63.34% common equity ratio was accepted. Indeed, the Company's proposed common equity ratio of 53.40% is entirely reasonable based on prior Commission action. Hence, the Company's actual common equity ratio conforms to Commission policy that the actual, not hypothetical, common equity ratio should be employed.

16. Q. Mr. Garrett also provides capital structure ratios for other industries. Is this information useful?

A. No. There is nothing useful that can be obtained from the tabulation of debt ratios shown on Figure 8 of OCA Statement No. 2. Mr. Garrett has not established a nexus between the debt ratios he provides and the cost of equity. It is not appropriate to compare the debt ratios for thousands of diverse companies to PECO without first establishing some level of comparability of these

companies.

17. Q. Is there another issue that should be considered regarding Mr. Garrett's hypothetical capital structure?

A. Yes. Another problem with Mr. Garrett's approach is that when proposing a hypothetical debt ratio, he creates a mismatch between the cost of long-term debt that he accepts and the hypothetical debt ratio that he advocates. This mismatch arises because the hypothetical long-term debt ratio contains more debt than the amount of long-term debt that is actually outstanding for PECO, which carries a 4.58% cost rate. That is to say, with more debt in the hypothetical capital structure, Mr. Garrett necessarily assumes a higher cost of debt than PECO actually has because of his higher hypothetical debt ratio. Mr. Garrett never addresses this inconsistency in his proposal, which provides yet another reason for his project be rejected.

III. PROXY GROUP

18. Q. Are there differences in the proxy groups utilized by the rate of return witnesses in this case?

A. Yes. Mr. Patel makes additions and deletions to my proxy group, while Mr. Garrett accepts my proxy group. Mr. Patel describes his criteria on page 8 of his direct testimony (I&E Statement No. 2). He includes all of my companies except NextEra Energy and adds seven additional companies. While I do not object to additional companies in theory, his barometer group is less comparable to PECO because they are geographically remote. Mr. Patel has not established the need to expand the number of companies in the barometer group by reaching for

companies that are geographically remote to PECO Energy.

19. Q. How do the revenue percentages compare for the members of your Electric Group in this case?

A. I have provided below the Percentage of Regulated Revenues, Income and Assets for my Electric Group. Those results are:

	Regulated and total Revenues		
Company	Percent	Regulated	Total
		($000,000)	
AVANGRID, Inc (AGR)	86%	$ 6,781	$ 7,923
Consolidated Edison Inc (ED)	92%	14,353	15,670
Dominion Energy, Inc. (D)	76%	12,983	17,174
Duke Energy Corporation (DUK)	100%	28,864	28,768
Eversource Energy (ES)	95%	11,621	12,289
Exelon Corp (EXC)	100%	19,078	19,078
FirstEnergy Corp (FE)	100%	12,432	12,459
NextEra Energy Inc (NEE)	82%	17,282	20,956
PPL Corp (PPL)	100%	7,879	7,902
Public Service Enterprise Group In	81%	7,935	9,800
Average	91%		

	Regulated and total Earnings		
Company	Percent	Regulated	Total
		($000,000)	
AVANGRID, Inc (AGR)	70%	$ 628	$ 901
Consolidated Edison Inc (ED)	87%	2,271	2,624
Dominion Energy, Inc. (D)	82%	2,513	3,057
Duke Energy Corporation (DUK)	120%	4,397	3,659
Eversource Energy (ES)	59%	832	1,412
Exelon Corp (EXC)	100%	2,054	2,054
FirstEnergy Corp (FE)	308%	1,351	439
NextEra Energy Inc (NEE)	89%	3,701	4,147
PPL Corp (PPL)	131%	988	756
Public Service Enterprise Group In	152%	1,565	1,031
Average	120%		

	Regulated and total Assets		
Company	Percent	Regulated	Total
		($000,000)	
AVANGRID, Inc (AGR)	68%	$ 28,069	$ 41,123
Consolidated Edison Inc (ED)	88%	60,956	69,065
Dominion Energy, Inc. (D)	70%	72,600	104,200
Duke Energy Corporation (DUK)	95%	168,515	178,086
Eversource Energy (ES)	67%	35,450	53,231
Exelon Corp (EXC)	98%	93,595	95,349
FirstEnergy Corp (FE)	99%	45,584	46,108
NextEra Energy Inc (NEE)	54%	86,559	158,935
PPL Corp (PPL)	110%	36,550	33,223
Public Service Enterprise Group In	82%	39,960	48,718
Average	83%		

(1) Excluding impairment of assets

In this table, I have shown that regulated revenues for each of the members of my Electric Group were 76% and above. The earnings and assets for my Electric Group were also all above 50%. There is thus no basis to alter my Electric Group in this case because all companies fit the 50% revenue criteria recently adopted by the Commission in its PECO Energy – Gas Division order.

20. Q. But what about Mr. Patel's selection criteria that specifies that the proxy companies must operate in a deregulated market?

A. After more than 20 years since the restructuring of the electric industry, this is no longer a valid screening criterion. Mr. Patel has not established a distinction between the cost of equity for a distribution-only electric utility and a fully integrated electric utility that owns regulated generation. Moreover, many of Mr. Patel's barometer group members have significant operations in a fully regulated integrated market. Examples would be American Electric Power, Dominion Energy, Duke Energy, Entergy, IDACORP, Portland General Electric, and Xcel Energy. If these companies qualify for membership in his barometer group, then NextEra, which operates a utility in Florida (Florida Power & Light), certainly does as well.

IV. COST OF COMMON EQUITY - DISCOUNTED CASH FLOW (DCF)

21. Q. The DCF model has been used by Mr. Patel, Mr. Garrett and you as one method to measure the cost of equity. What is your position concerning the usefulness of the DCF method?

A. While the results of a DCF analysis should certainly be given weight, the use of more than one method provides a superior foundation for the cost of equity determination. Since all cost of equity methods contain certain unrealistic and

overly restrictive assumptions, the use of more than one method will better capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing). I am aware that the Commission usually expresses its cost of equity determination in the context of the DCF model. But the Commission also considers other methods as well. In its order entered on December 28, 2012, in Docket No. R-2012-2290597, the Commission stated:

> Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation.[2]

Similarly, in the Aqua Pennsylvania decision, the Commission observed:

> In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[3]

[2] *Pennsylvania Public Utility Commission v. PPL Electric Utilities*, Docket No. R-2012-2290597, meeting held Dec. 5, 2012, at 80.
[3] *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, Docket No. R-2021-3027385, order entered May 16, 2022, at 154-55.

Again, the Commission recognized the need for additional methods in its decision for Columbia Water:

> In *Aqua 2022*, the Commission determined the ROE by using informed judgement based on I&E's DCF and CAPM methodologies. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. We historically have primarily relied upon the DCF methodology in arriving at ROE determinations and utilized the results of the CAPM, as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our ROE determination.[4]

The Commission has consistently acknowledged the usefulness of other methods, such as CAPM, as a means of establishing a range of reasonable returns – particularly in times of high interest rates. Indeed, it is clear that the Commission has been guided by the results of other models and other factors aside from DCF when setting the DSIC return. The Commission's selection of the rate of return on equity for use in the DSIC is usually set well above the cost of equity indicated by the DCF model alone. Therefore, the use of multiple methods provides a more comprehensive and reliable basis to establish a reasonable equity return for PECO than does sole reliance on the DCF. Indeed, Mr. Garrett agrees with my position when he states: "It is preferable to use multiple models because the results of any one model may contain a degree of imprecision, especially depending on the reliability of the inputs used at the time of conducting the model" (see page 10 of OCA Statement No. 2).

[4] *Pennsylvania Public Utility Commission v. Columbia Water Company*, Docket No. R-2023-3040258 (Order entered Jan. 18, 2024)("*Columbia Water*"), at 108.

22. Q. What has Mr. Patel done with the results of models other than DCF?

A. Nothing. In this case, Mr. Patel essentially ignores the results of the CAPM, calling his CAPM results a basis for comparison purposes only (see pages 17, 18, 19, 24, 26, 33 and 37 of I&E Statement No. 2). Unlike Mr. Patel, Mr. Garrett acknowledges that the use of multiple methods provides a more comprehensive and reliable basis to establish a reasonable equity return for PECO (see page 10 of OCA Statement No. 2). In his testimony, Mr. Patel shows that the average DCF result is too low by reference to his CAPM results. In this situation, the Commission should consider moving to within the top half of the range of DCF returns submitted in this case due to this understatement. This process would preserve use of DCF, but also accommodate the tendency of the DCF model to understate the required return in this market. Mr. Patel's DCF return range is from 8.23% for IDACORP to 13.92 for Portland General Electric. Since Mr. Patel's CAPM result is 11.29%, then it stands to reason that the top half of the range of DCF results should be emphasized in this case, because the average DCF by itself is too low. If the DCF is to be used exclusively, as argued by Mr. Patel, then the proper DCF return should be within the top half of the range, i.e., 9.91% to 13.92%, before any consideration of management performance. A return of 11.92% (9.91% + 13.92% = 23.83% ÷ 2) would rest at the midpoint at the top half of the range.

Indeed, the CAPM and RP methods, which directly reflect changes in interest rates, are an important indicator of higher equity cost rates. Although Mr. Patel claims (see pages 25-26 of I&E Statement No. 2) that DCF sufficiently considers economic factors, including inflation, there is no input in the DCF that Mr. Patel

can point to that substantiates his position. Indeed, when viewing the components of the DCF model, i.e., D = dividend payments, P = stock price, and g = growth, dividend payments are a function of a company's earnings ability and internal cash flow needs, the stock price is influenced by a host of factors, such as investor sentiment, computer-generated program trading and others, and the growth rate is based on consensus estimates of analysts that do not define the myriads of factors that underline those growth rates. We know that CAPM and RP reflect directly changes in interest rates and those models are more responsive to inflation in this regard than DCF.

23. Q. Has the National Association of Regulatory Utility Commissioners ("NARUC") taken a position on the use of multiple methods to measure the cost of equity?

A. Yes. NARUC has published a paper titled "Cost of Capital and Capital Markets Primer for Utility Regulators." In it, NARUC said:

> The goal of all cost of equity models is to capture the realities of the capital marketplace and each model does so from a different perspective. Because these financial models are simplifications of the real world, the ROE results are estimates rather than exact discernments of ultimate truth. Ideally, the model results will corroborate each other but may not in practice. Different estimates resulting from different models can usefully frame, bracket, or define a range or zone of estimates.

Investors, investment bankers, and corporate financial professionals use multiple models when evaluating the cost of equity. Likewise, it is desirable for regulators to also use multiple models when evaluating the cost of equity.

24. Q. What form of the DCF model has been employed in this case?

A. The constant growth form of the DCF model has been used by Mr. Patel, Mr. Garrett, and me.

25. Q. Are there limitations to the application of the DCF that indicates that it should not be used alone to establish the equity return, which Mr. Patel seems to support?

A. There are many assumptions associated with the specification of the DCF. These are:

- The form of the model. A choice must be made whether to employ the continuous or discrete form of the model.
- Whether a finite or infinite form of the model realistically represents investor's horizon.
- Whether compounding of the quarterly dividend should be employed.
- The timing of the dividend payments regarding the interval from the ex-dividend date and the stock measurement date needs to be addressed.
- A choice is necessary relative to a representative price that would reasonably represent the rate effective period, e.g., 12-month average, 6-month average, 13-week average, spot, etc.
- Assumptions concerning the structure of returns, which under the DCF assume that the price-earnings multiple, dividend payout ratio, and earned return will be constant.
- Whether single or multiple growth rates better reflect investor expectations.
- Choices concerning the use of historical or forecast growth rates.

- From a historical perspective, whether 10 years, 5 years, or some other historical period is representative of investor expectations.
- Choice among variables to measure growth, e.g., earnings per share, dividends per share, book value per share, cash flow per share, retention growth, price growth.
- Choice of investor influencing growth rates that are available from I/B/E/S First Call, Zacks, Morningstar and Value Line.
- Whether the growth rate if measured by the formula "b x r" should be modified for external growth, i.e., "sv."
- The potential misspecification of the rate of return applicable to book value when taken directly from DCF if the market price diverges from book value.

Many of the assumptions, especially the constant price-earnings multiple, constant payout rate, and constant earned return, are particularly unrealistic. My point is that all models have their strengths and weaknesses, and it is important to rely on more than one model in determining the cost of common equity, as the Commission has done.

26. Q. Mr. Patel presents a revenue requirements calculation showing the difference associated with using the DCF and CAPM results (see pages 36-37 of I&E Statement No. 2.) What does this comparison reveal?

A. This comparison is not relevant to this case. The Commission has used the DCF and CAPM models to establish a range, and the authorized return would fall within that range. If a valid comparison can be made with these inputs, it would be between the midpoint of the range, i.e., 10.60% (11.29% + 9.91% = 21.20% ÷

2) and the lower end of the range, i.e., 9.91%. This would then provide a point of reference between an approach that gives equal weight to both the DCF and CAPM and to using DCF alone. That produces a $48.169 million difference in revenue requirements, not the $96.377 million Mr. Patel reports.

27. Q. Do the DCF results proposed by Mr. Patel provide a reasonable representation of the cost of equity?

A. Not in my opinion. The principal purpose of assembling a barometer group is to avoid relying on data for a single company that may not be representative and to thereby smooth out any abnormalities. That said, when some of the DCF results for companies in the barometer group are unreasonable on their face, the reliability of the method being used, or the witness's application of that method, must be questioned. Mr. Patel himself realizes that some of his results are unreasonable on their face. For example, he removes what he believes is an unduly high growth rate for Dominion Energy. Yet, he leaves in unduly low results for IDACORP. As indicated below, several DCF results fall into the unduly low category using data contained in I&E Exhibit No. 2:

Company	Average: 52 wk & Spot Yield	+	Growth	=	Total
AVANGRID	4.95%	+	3.30%	=	8.25%
Consolidated Edison, Inc.	3.62%	+	4.70%	=	8.32%
IDACORP, Inc.	3.53%	+	4.70%	=	8.23%

It is a fundamental tenet of finance that the cost of equity must be higher than the cost of debt by a meaningful margin to compensate for the higher risk associated with a common equity investment. Yet, each of the companies listed above has

DCF returns calculated by Mr. Patel that fail to provide a sufficient spread over the May 2024 yield of 5.74% on A-rated public utility bonds. As I have demonstrated in my direct testimony (PECO Statement No. 5, pages 42-43), the spread between the cost of debt and cost of equity should be 6.50% in this market environment. As such, none of the returns listed above for the three companies comes close to meeting this standard. If these three companies were excluded, Mr. Patel's cost of equity would be 10.28% (4.31% + 5.97%) for the remaining companies in Mr. Patel's group.

V. DCF GROWTH RATE

28. Q. As to the DCF growth component, what financial variables should be given greatest weight when assessing investor expectations?

A. The theory of the DCF holds that (1) the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share with a constant P-E ratio and (2) dividend growth will equal earnings growth with a constant payout ratio. Therefore, to properly reflect investor expectations within the limitations of the DCF model, earnings per share growth, which is the basis for the capital gains yield and the source of dividend payments, must be given the greatest weight. The reason that earnings per share growth is the primary determinant of investor expectations rests with the fact that 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). It is also important to recognize that analysts' earnings growth rate forecasts significantly influence investor growth expectations. Moreover, it is instructive to note that Professor Myron Gordon, the foremost proponent of the DCF model in public utility rate cases, has

established that the best measure of growth for use in the DCF model is forecasts of earnings per share growth.[5] These growth rates relate specifically to each company whose cost of equity is being analyzed.

29. Q. Please summarize the DCF growth rate analysis performed by Mr. Patel.

A. As shown on page 29 of I&E Statement No. 2, Mr. Patel proposes a growth rate of 5.65%, based on his review of analysts' projected earnings growth rates. But his proposed growth rate was developed after first eliminating the Yahoo! Finance growth rate for Dominion Energy. The approach taken by Mr. Patel introduces a downward bias to his DCF calculations. Had he used the actual data, his DCF return would be 10.23% (4.26% + 5.97%). To provide a balanced growth rate, Mr. Patel should have also removed the anomalous (i.e., extremely low) growth rate for AVANGRID of 0.40% if his Dominion Energy exclusion is valid. That would have resulted in a 5.74% barometer group growth rate, thereby providing a 10.00% (4.26% + 5.74%) DCF. Whether restoring the Dominion Energy growth rate (e.g., 10.23% DCF return) or removing the AVANGRID growth rate (e.g., 10.00% DCF return), it is apparent that Mr. Patel's DCF analysis is unbalanced.

30. Q. In his testimony, Mr. Garrett proposes to use a "sustainable" growth rate that is not specific to his proxy group of gas companies. Does this follow the

[5] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould. "We have compared the accuracy of four methods for estimating the growth component of the discounted cash flow yield on a share: past growth rate in earnings (KEGR), past growth rate in dividends (KDGR), past retention growth rate (KBRG), and forecasts of growth by security analysts (KFRG) … we have three observations to make. First, the superior performance by KFRG should come as no surprise. All four estimates of growth rely upon past data, but in the case of KFRG a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth."

traditional approach for applying the DCF model?

A. No. His testimony does not follow the normal, or typical, processes of applying the DCF model long used by the Commission and others for determining the return on equity. His approach to looking at GDP growth is certainly alien to all DCF analyses that are familiar to the Commission. On this basis alone, the DCF analysis submitted by Mr. Garrett in this case should be dismissed. I say this because, as I previously explained, Myron Gordon established that analysts' forecasts of earnings growth are the correct input for the DCF for each member of the proxy group.

31. Q. What DCF growth rate did Mr. Garrett actually use in his DCF?

A. On Exhibit DJG-6, Mr. Garrett provides two very different expressions of DCF. One DCF calculation uses Mr. Garrett's unique view of sustainable growth and the second DCF results reflects analysts' growth rates, which are familiar to the Commission. The most obvious problem with Mr. Garrett's testimony concerns his development of the sustainable growth rate form of the DCF model for determining the ROE. In this regard, he advances the proposition that the growth rate for a utility can never exceed the long-term gross domestic product ("GDP") of the country. As I have explained in my direct testimony, companies, including utilities, can cycle through the growth phases. While Mr. Garrett lists other lower criteria for determining the long-term growth rate, his long-term estimate of GDP growth is 3.8%, Exhibit DJG-5. This growth rate is well below analysts' projections of earnings growth used by Mr. Patel and me, and it produces a nonsensical DCF cost rate of 8.0%.

32. Q. Do the DCF growth rates proposed by Mr. Garrett provide a reasonable input in the cost of equity analysis using the DCF model?

A. No. Mr. Garrett indicates that his method for analyzing sustainable growth rate rests on (i) nominal GDP, (ii) real GDP, and (iii) the PECO load/customer growth. There are many problems with his approach. First, the combination of the real GDP growth and inflation equals nominal GDP, i.e., (1.017) * (1.020) = (1.0373 -1) = 3.7%, which approximates his nominal GDP growth. Second, earnings growth occurs through revenue growth, net of O&M, depreciation, taxes, and interest. None of these factors are addressed with the risk-free rate of return. Third, Mr. Garrett is essentially developing a generic growth rate that would apply to any, or all, companies, whether they are regulated or non-regulated companies. However, each company has a unique company-specific growth rate. His approach is simply incompatible with the basic concept of the DCF, where future cash flows for each company are systematically related to one another by a constant growth rate that represents a basic tenant of the single-stage DCF. It is also incompatible with the use of the growth rates of a comparable barometer group of companies to meet the requirement that a utility is to be permitted to earn a return equal to comparable companies. The DCF equation is P = D / (k-g). Mr. Garrett's growth rate does not fit within this equation.

33. Q. Does Mr. Garrett's alternative DCF calculation provide an improvement on his preferred sustainable DCF calculation?

A. It is a step in the right direction, but it too is deficient. While using analysts' forecasts, which have been demonstrated to be a superior growth rate measure in

the DCF,[6] his calculations still fall short. This is because Mr. Garrett erroneously used the Value Line forecast growth rate of dividends per share rather than earnings per share.[7] Correcting for this error, the DCF growth rates are shown below:

Analysts' Five-Year Projected Growth Rates

Electric Group	Value Line Earnings Per Share
AVANGRID, Inc.	3.50%
Consol. Edison	6.00%
Dominion Energy, Inc.	3.00%
Duke Energy	5.00%
Eversource Energy	6.00%
Exelon Corp.	NMF
FirstEnergy Corp.	5.50%
NextEra Energy	8.00%
PPL Corp.	7.50%
Public Serv. Enterprise	5.00%
Average	5.50%

Source of Information :
Value Line Investment Survey, May 10, 2024

Had he used this correct growth rate, he would have then produced a DCF return of 9.6% (4.1% + 5.5%) rather than 9.0%. This indicates that his DCF return is completely inadequate for the reasons explained above.

[6] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould. "We have compared the accuracy of four methods for estimating the growth component of the discounted cash flow yield on a share: past growth rate in earnings (KEGR), past growth rate in dividends (KDGR), past retention growth rate (KBRG), and forecasts of growth by security analysts (KFRG) … we have three observations to make. First, the superior performance by KFRG should come as no surprise. All four estimates of growth rely upon past data, but in the case of KFRG a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth."

[7] Mr. Garrett used the "Percent Retained the Common Equity" for Exelon where no growth rate was shown and "Earnings per Share" growth for PPL where the dividend growth rate was negative.

VI. LEVERAGE ADJUSTMENT

34. Q. Please respond to Mr. Patel's criticism of your leverage adjustment.

A. In his discussion of my leverage adjustment, Mr. Patel mentions the market-to-book ("M/B") ratio at page 48 of I&E Statement No. 2. I need to be clear that my leverage adjustment is not designed to produce any particular M/B ratio. Mr. Patel offers three reasons for not making a leverage adjustment. First, Mr. Patel notes that the credit rating agencies assess financial risk in terms of a company's income statement in their analysis of the creditworthiness of a company. I agree. But this has nothing to do with my leverage adjustment. The credit rating agencies do not measure the market required cost of equity for a company. The credit rating agencies are only concerned with the interests of lenders. They are judging risk associated with a company's ability to make timely payments of principal and interest. Hence, they are not concerned with the cost of equity or how it is applied in the rate-setting context. While Mr. Patel's observation is correct, it has no relevance to my leverage adjustment.

35. Q. Second, Mr. Patel also questions your leverage adjustment by reference to prior Commission orders. Please comment.

A. Mr. Patel points to several decisions where the Commission declined to make a leverage adjustment – i.e., rate cases including Aqua Pennsylvania, the City of Lancaster Water Department, UGI Utilities – Electric Division, and Columbia Gas of Pennsylvania. The fact that the Commission declined to use the leverage adjustment in the Aqua Pennsylvania case cited by Mr. Patel does not invalidate its use. Notably, the Commission did not repudiate the leverage adjustment in the Aqua case, but instead arrived at an 11.00% return on equity for Aqua by

including a separate return increment for management performance. Just as an increment for management performance is not recognized in all rate cases, so too the Commission seems to be taking a similar approach to the leverage adjustment. As to the City of Lancaster decision, the situation there was quite different than the leverage adjustment that I propose in this case. Lancaster proposed a leverage adjustment to the cost of equity measured with the Hamada formula and applied it to the DCF result, the Risk Premium result, and the CAPM. While the Hamada formula plays a role in the CAPM, it is not applicable to the DCF or the Risk Premium measures of the cost of equity. Hence, this distinguishes the City of Lancaster approach to the leverage adjustment from mine in this case. As to the UGI – Electric Division case, there the Commission granted a management performance increment rather than a leverage adjustment when arriving at a 9.85% equity return. And for Columbia, the Company accepted the I&E's recommendation of the allowed return, which was 9.86%, in a case litigated at the height of the COVID-19 Pandemic. Thus, Columbia chose not to argue the leverage adjustment in Exceptions to the Commission. However, based upon the current inputs to the DCF that indicate a low result, the Commission should now consider using the leverage adjustment, just as it did previously when the DCF was suggesting unusual results. In the PECO Energy Company – Gas Division rate case, the Commission arrived at a 10.24% return without the leverage adjustment, because that return was already deemed to be on the higher side and no additional adjustment was warranted. Finally, the Commission set the equity return at 10.00% for Aqua Pennsylvania recently without a leverage adjustment, but with an adjustment for management

performance.

36. Q. Third, Mr. Patel argues that investors base their decisions on the book value debt and equity ratios for regulated utilities. Please respond.

A. Mr. Patel contends that information presented to investors, such as that included in the Value Line reports (see page 54 of I&E Statement No. 2), argues against my leverage adjustment because investors base their investment decisions on book value. However, the Value Line reports clearly show the market capitalization of each company in his barometer group. This means that investors are well aware of the market capitalization of the electric utility stocks that Mr. Patel relies upon for his analysis of the cost of equity. More importantly, I fundamentally disagree that investors base their decisions on book values. To the contrary, it is the future cash flows that investors expect to realize that determine the price they are willing to pay for a share of common equity. Stated differently, investors are concerned with the return that will be earned on the dollars they invest (i.e., their market price) and not some accounting value of little relevance to them. The financial risk associated with the book value capital structure is different from the market value of the capitalization. I clearly demonstrate this point on Schedule 10 of PECO Exhibit PRM-1. Hence, the observation of Mr. Patel is misplaced because I have clearly shown the difference in financial risk, and that risk difference must be taken into account when arriving at an equity return that is applicable to the weighted average cost of capital using book value weights.

37. Q. Mr. Garrett criticized the leverage adjustment that you propose to account for the divergence of market capitalization and book value capitalization. Please comment.

A. At pages 28-30 of OCA Statement No. 3, Mr. Garrett never really refutes my leverage adjustment. Indeed, he employs my leverage adjustment approach through the use of the Hamada formula to unlever and relever betas as part of his capital structure analysis, thereby validating my approach. First, in the DCF approach, I did not use the Hamada formula, but rather I used the Modigliani & Miller approach. Second, at page 63 of OCA Statement 2, Mr. Garrett claims that the Hamada formula generates an unlevered beta of 0.48. But what I have shown is that the correct unlevered beta is 0.58 (see Schedule 10 of PECO Energy Exhibit PRM-1). The reason for the difference is that I correctly use the market capitalization for my calculation, including the market value of debt, and Mr. Garrett did not because he used the book value capital structure ratios of the proxy group. Indeed, if Mr. Garrett had used the market capital structure ratios of the proxy group, he would have calculated a different unlevered beta.

VII. COST OF COMMON EQUITY - CAPITAL ASSET PRICING MODEL

38. Q. Do you have concerns regarding Mr. Patel's and Mr. Garrett's applications of the CAPM?

A. Yes. Mr. Patel's CAPM analysis understates the cost of equity for a number of reasons: (i) his use of the yield on 10-year Treasury notes, (ii) his failure to use leveraged adjusted betas, and (iii) his failure to make a size adjustment. The results of Mr. Garrett's CAPM approach are simply much too low.

39. Q. How does the use of the yield on 10-year Treasury notes compare with yields on longer-term Treasury bonds?

A. The Blue Chip reports dated May 31, 2024, show this comparison. For the first quarter of 2024, the gap was 0.17% (4.33% - 4.16%) between the yields on 30-year and 10-year Treasury obligations. For the period from 2026 to 2030, that gap is projected at 0.20% (4.3% - 4.1%). This shows a systematic understatement of Mr. Patel's CAPM returns. This understatement can be traced to extraordinary monetary policy actions taken by the FOMC to deal with the recession that followed the onset of the COVID-19 Pandemic. Shorter-term rates, such as 10-year notes, respond more to the policy initiatives of monetary officials, while long-term rates, such as 30-year bonds, are more a reflection of investor sentiment of their required returns. For this reason, long-term rates, such as those revealed by 30-year Treasury bonds, should be used to measure the risk-free rate of return. Use of shorter-term rates, such as Mr. Patel's 10-year Treasury Notes yields, are more susceptible to Fed policy actions. While I am aware that the Commission has used the yield on 10-year Treasury Notes in past decisions, the yield on 30-year Treasury bonds is the better choice because it reflects the long-term nature of fixed assets that utilities employ to provide service. Just consider the average service life used in establishing the Company's depreciation accrual rates.

40. Q. How has Mr. Patel understated the risk-free rate of return?

A. The support for his risk-free rate of return is shown on his Schedule 8 of I&E Exhibit No. 2. There, he incorrectly gives the same weight to the yield on 10-year Treasury notes for the third and fourth quarters of 2024, and first, second,

and third quarters of 2025, as he does for the entire five-year period 2025 through 2029. This approach leads to a seriously understated risk-free rate of return. Even if 10-year rates are used, it is necessary to correct the weights assigned to the forecast data presented by Mr. Patel. I have revised his forecast below, based upon the Blue Chip publication dated June 1, 2021. Moreover, Blue Chip provides higher yields on Treasury obligations, as the forecasts are extended into the future.

Year	10-Year Treasury Yield	30-Year Treasury Yield
2025	4.0%	4.2%
2026	4.0%	4.2%
2027	4.0%	4.2%
2028	4.0%	4.3%
2029	4.2%	4.4%
2030	4.2%	4.4%
Average	4.1%	4.3%

The resulting risk-free rate of return is 4.1% using the yield on 10-year Treasury Notes and 4.3% using the yield on 30-year Treasury Bonds.

41. Q. How should these results be used in the CAPM?

A. The risk-free rate of return should be calculated with the data that I present above. I have corrected Mr. Patel's CAPM as indicated below using those inputs and the forecast yield on 10-year Treasury bonds:

	Rf	+	β	(	Rm	-	Rf	)	=	K
Electric Group	4.3%	+	0.91	(	12.00%	-	4.3%	)	=	11.31%

42. Q. Mr. Garrett has also performed a CAPM calculation in addition to his DCF analysis. Are the results of his CAPM useful in setting the Company's equity return in this case?

A. No. There are a variety of problems with Mr. Garrett's CAPM approach which makes it not useful in this case. He makes CAPM calculations that produce results of 9.6%. The inadequacy of his calculations is shown by the Commission's most recent Quarterly Earnings Report, which produces a CAPM return of 11.34% for the Electric Company Barometer Group that exceeded substantially the DCF return. His first error is in his use of a backward-looking 4.7% yield on 30-year Treasury bonds. A 30-day historical average period is not compatible with the Commission's use of forecast Treasury yields (see UGI - Electric Division at Docket No. R-2017-2640058, Order Entered October 25, 2018). Second, the 5.2% equity risk premium ("ERP") selected by Mr. Garrett is well off the mark. This is shown by Mr. Patel's data that provides a market risk premium of 7.93% (12.00% - 4.07%), as well as my own determination of an 8.26% market risk premium. Both Mr. Patel and I have considered both historical data and investor expected future returns when measuring the equity risk premium. Mr. Garrett used three approaches. He did not rely upon on historical analysis, with good reason, because it erroneously employed geometric means. His other approach (i.e., "implied equity risk premium") is likewise deficient because his 9.8% market return is much too low, as shown by my data (i.e., 11.93% forecast market return) and Mr. Patel's data (i.e., 12.0% forecast market return). His last method "ERP surveys" are not conclusive because Mr. Garrett has not shown that current investors consider or use this method.

Furthermore, the implied total market return using Mr. Garrett's inputs is just 9.9% (4.7% + 5.2%), which is clearly incompatible with actual stock market returns of 26.29% in 2023, a five-year annualized return of 17.36%, and 12.0% on average for the past 97 years (1926–2022). It is also well off the market given Mr. Patel's determination that the total market return is 12.0%.

VIII. COST OF COMMON EQUITY - RISK PREMIUM ANALYSIS

43. Q. Do you believe the Risk Premium method provides significant evidence of the cost of equity?

A. Yes. In my opinion, the Risk Premium results should be given serious consideration. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides the foundation for its cost of equity which must be higher than the cost of debt in recognition of the higher risk of equity (see pages 39-40 of PECO Energy Statement No. 11). So, while Mr. Patel and Mr. Garrett decline to use the Risk Premium approach to measure the Company's cost of equity, it is an approach that provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk. It is particularly useful when investors expect changes in the cost of debt prospectively, which is currently the expectation of investors, as I have explained at pages 39-43 of PECO Energy Statement No. 5. Indeed, the Risk Premium approach provides for direct reflection of prospective interest rates in the model and therefore should be given weight in determining the equity cost rate in this case.

44. Q. Please respond to Mr. Garrett's criticisms of your Risk Premium approach.

A. While Mr. Garrett declines to use the Risk Premium approach to measure the Company's cost of equity, it is an approach that provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk. In fact, it is precisely because investors consider the results of other methods that those methods should be used in addition to the DCF in the development of the cost of equity in this proceeding. As I explained in my direct testimony, we are facing the prospect of increasing interest rates for the future and the market has increased yields on debt instruments. At this point, it is speculative to infer that the FOMC is at the threshold of cuts in the Fed Funds rate as I explained above. I incorporated the trend toward lower interest rates when I developed my Risk Premium cost of equity of 11.50% (5.00% interest rate on A-rated public utility bonds + 6.50% equity risk premium).

45. Q. What does Mr. Patel say about your Risk Premium analysis?

A. Mr. Patel makes the unfounded assertion that the Risk Premium and CAPM methods should only be used as a comparison to the results of the DCF method because they do not carry over from the investment decision-making process to the utility rate-setting process (see page 21 of I&E Statement No. 2). In fact, it is precisely because investors consider the results of other methods that they too should be used in addition to the DCF in the development of the cost of equity in this proceeding. Mr. Patel's assertion that the Risk Premium method does not measure the current cost of equity as directly as the DCF is similarly without foundation. As I explained in my direct testimony and earlier in this rebuttal

testimony, we are facing a relatively high level of interest rates for the foreseeable future. I incorporated the trend toward higher interest rates when I developed my Risk Premium cost of equity of 11.50%. Hence, my Risk Premium cost rate is fully responsive to changing market fundamentals and the credit quality of the Electric Group.

IX. COST OF COMMON EQUITY - COMPARABLE EARNINGS APPROACH

46. Q. Please respond to the criticism of the Comparable Earnings approach.

A. The underlying premise of the Comparable Earnings method is that regulation should emulate results obtained by firms operating in competitive markets and that a utility must be given an opportunity cost of capital equal to that which could be earned if one invested in firms of comparable risk. For non-regulated firms, the cost of capital concept is used to determine whether the expected marginal returns on new projects will be greater than the cost of capital, i.e., the cost of capital provides the hurdle rate at which new projects can be justified, and therefore undertaken. Further, given the 10-year time frame (i.e., five years historical and five years projected) considered by my study, it is unlikely that the earned returns of non-regulated firms would diverge significantly from their cost of capital.

The Comparable Earnings approach satisfies the comparability standard established in the *Hope* case.[8] In addition, the financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies

[8] *F.P.C. v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*").

can compete effectively in the capital markets. Moreover, in a 1994 study that addressed the ROE issue, John Olson (then with Merrill Lynch) established that ROEs from non-regulated companies provide better assessment of investor requirements than those available for regulated utilities.[9]

X. WALMART AND ADDITIONAL OCA PROPOSALS

47. Q. Walmart witness Ms. Lisa Perry argues that the cost of capital for PECO Energy is lower than proposed by the Company based generally on rate case decisions by other state regulatory commissions. Do you agree?

A. No. As I explained previously, decisions of the Pennsylvania Commission should provide a guide to the equity return in this case, rather than actions by other state commissions. If there is any merit to other authorized returns, then the 10.35% equity return in PECO Energy's transmission business should serve as a point of reference. The general theme of the witness for Walmart is that the trend in authorized returns has been lower in recent years and that other state commissions are granting lower returns. I agree that the trend has been lower, but some context is required for this information to be useful. It is obvious that as the authorized returns have declined, the "regulatory premium," here defined as the authorized return less the yield on A-rated public utility bonds, has expanded. This is revealed by the data shown below:

[9] "Natural Gas: The Case for ROE Reform," John E. Olson, First Vice President, Merrill Lynch & Co., Oct. 11, 1994.

Years	Number of Years	Average Regulatory Risk Premium
1984-2024	41	4.26%
2005-2024	20	5.16%
2015-2024	10	5.41%
2020-2028	5	5.11%

Indeed, it is not the authorized returns viewed in isolation that are important, but how those returns are viewed by reference to changes in interest rates. What the table provided above shows is that the "regulatory premiums" have increased during periods of declining interest rates. This is entirely consistent with the relationship of the risk premiums and interest rates that I describe in my direct testimony (see page 43 of PECO Energy Statement No. 5). We can see that the "regulatory risk premiums" have expanded in recent periods in the response to the decline in public utility bond yields. That fact has not been adequately reflected in the proposal by Ms. Perry.

48. Q. OCA witness Roger Colton argues that establishing a cost of equity is "fundamentally predicated on balancing consumer and investor interests" and must be determined with reference to whether a "sizeable portion" of customers can afford to pay the resulting utility rates (OCA Statement No. 1, p. 16). He also contends that the "greater adverse impacts that inflation has imposed on low-income customers when setting rates" and determining a cost of equity (p. 19). How do you respond?

A. OCA witness Roger Colton makes some very broad statements regarding the need to consider consumer's ability to pay in setting PECO Energy's return on

equity. Mr. Colton's claims are entirely inconsistent with fundamental principles of *Hope*. Indeed, during the COVID-19 Pandemic, witnesses from the OCA made similar arguments against rate increases during that time. The Commission roundly rejected those OCA arguments then and should do so now. The Commission has always weighted the balance of ratepayers and investors in setting rates. That balance has been a key to providing utilities with the ability to attract capital. Indeed, utilities, such as PECO Energy, must provide service to their customers at all times, and to do so it must be in a capital attraction position at all times. Mr. Colton's proposal does not comply with the capital attraction standard of a fair return. No one has contested the need for PECO Energy to undertake new investment in this case. As a consequence, an adequate return is a prerequisite to attract necessary capital for infrastructure investment. In fact, the effects on low-income customers that Mr. Colton addresses are matters for the design of PECO's universal service programs.

49. Q. OCA witness Clarence Johnson argues that there is some linkage between the Company's rate of return and the rate design associated with method used to recover fixed costs. Please respond.

A. In my opinion, there is no practical means to quantify any purported, if any, linkage between the two issues. Mr. Johnson has not proposed any basis points adjustment to the rate of return associated with shifting revenue requirements recovered in the Company's tariff from variable rates to the customer charge or vis-versa. He has not quantified his position on this matter because none is possible. From a cost of equity perspective, the risk associated with rate design issues are an unsystematic (i.e., company-specific) risk that receives no

compensation (i.e., not addressed) in the CAPM formula. Other methods that may be employed to measure the cost of equity (e.g., DCF) contain no components (i.e., yield, growth, leverage) that could be quantified to account for rate design variations. The bottom line is that Mr. Johnson's proposal has no merit because there is no way to implement it.

XI. MANAGEMENT PERFORMANCE

50. Q. Both Mr. Patel and Mr. Garrett oppose any recognition for management performance in the determination of the return on equity. Mr. Patel and Mr. Garrett assert that PECO Energy has only done what it is required to by law. How do you respond?

A. As I stated in my direct testimony, I believe PECO Energy has performed in an exemplary manner, as explained by PECO Energy Witness Ms. LeVine, and that performance should be recognized in this case. Mr. Patel simply disagrees, without addressing any of the items highlighted by Ms. LeVine as examples of PECO Energy's excellent performance. Mr. Garrett's position regarding management performance is that the models of the cost of equity already incorporate management effectiveness. In each case, neither Mr. Patel nor Mr. Garrett has shown that PECO Energy is not entitled to some form of management performance recognition by the Commission. Ms. LeVine's direct and rebuttal testimony establish that the Company's management performance warrants recognition by the Commission. Ms. Perry also discusses the management enhancement, as do both Mr. Colton and OCA witness Nicholas DeMarco. My assessment of their testimony indicates that other PECO witnesses have addressed the performance issues which justify inclusion of a management

performance increment in this case.

51. Q. OCA witness Garrett argues (see page 50 of OCA Statement 2) that additional basis points for management performance would charge individually the Electric Division ratepayers and the Gas Division ratepayers a higher equity return for services provided by the diversified PECO Energy. He seems to find fault with this proposition, as does OCA witness DeMarco (see pages 4-5 of OCA Statement 5), who contends that PECO should not be able to "double-dip." Please respond.

A. It is not entirely clear to me what Mr. Garrett or Mr. DeMarco find wrong with each division receiving recognition of management performance. Each division has its own cost of service, rate base, and a return on that rate base. The Company witnesses have substantiated its superior management for each division individually. By considering management performance individually for each division would not result in any double counting for it, if that is what bothers Mr. Garrett and Mr. DeMarco. Moreover, not all of PECO Energy customers take both services from the Company. Some customers receive electric service and no gas service and some customers receive gas service and no electric service. Each division's rates are determined individually, and so should consideration of management performance.

XII. SUMMARY

52. Q. Please summarize your rebuttal testimony.

A. It is my opinion that the equity allowances proposed by Mr. Patel and Mr. Garrett significantly understate the cost of common equity for PECO. In an environment

of prospectively higher interest rates and Company-specific risk factors, an opportunity to earn a cost of equity of 10.95%, including recognition of management performance, is reasonable for PECO. Furthermore, Mr. Garrett's capital structure proposal should be rejected for all the reasons previously stated. Indeed, the PECO capital structure proposed by the Company is entirely reasonable for this case. Finally, recognition of the exemplary performance of the Company's management should be recognized by the Commission.

53. Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2024-3046931**
	:	
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Paul R. Moul, hereby state that I am the Managing Consultant of the firm P. Moul & Associates; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 5
- PECO Exhibit PRM-1

- PECO Statement No. 5-R

Dated: August 5, 2024

Paul R. Moul

PECO Statement No. 6:

Direct Testimony of
Tamara J. Jamison

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-2024-3046931

DIRECT TESTIMONY

WITNESS: TAMARA J. JAMISON

SUBJECT: CLASS COST-OF-SERVICE STUDY

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
TAMARA J. JAMISON

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Tamara J. Jamison. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Manager, Revenue Policy.

3. Q. Please describe your educational background.

A. I received a Bachelor's degree in Business Administration with a concentration in Accounting from Georgetown University. I am also a Certified Public Accountant in Pennsylvania.

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

A. Upon graduation from Georgetown University, I worked in Deloitte's Assurance and Advisory practice. I was hired by PECO as a Senior Accountant in 2006. I was promoted to a Principal Revenue Accountant in 2008. In 2013, I was promoted to a Senior Manager in Finance. I was appointed Senior Manager of Revenue Policy in PECO's Regulatory Strategy and Revenue Policy Division in 2020. In that capacity, I am responsible for managing certain regulatory filings,

audits, and specific segments of larger regulatory proceedings, including evaluating, analyzing and supporting the Company's requests for changes in revenue related to its regulated electric distribution and transmission businesses and its gas distribution business. I am also responsible for providing expert testimony and coordinating the preparation of testimony by other witnesses on behalf of the Company with respect to various regulatory issues.

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

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

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

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

7. Q. How is your testimony organized?

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

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

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

PECO Exhibit TJJ-1	Summary of Results
PECO Exhibit TJJ-2	Total Class Allocation - Revenue Requirement by Rate Class
PECO Exhibit TJJ-3	Revenue Requirement by Functional Classification
PECO Exhibit TJJ-4	Unitized Functionally Classified Revenue Requirement
PECO Exhibit TJJ-5	Customer-Related Revenue Requirement and Customer Charge
PECO Exhibit TJJ-6	Night Service Rider-Related Costs
PECO Exhibit TJJ-7	Development of External Allocation Factors
PECO Exhibit TJJ-8	Development of Unbundled Cash Working Capital Rate for the Generation Supply Adjustment
PECO Exhibit TJJ-9	Development of Unbundled Cash Working Capital Rate for the Transmission Service Charge

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

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

A. I used the total distribution revenue requirement for the fully projected future test year ("FPFTY") developed in PECO Exhibit MJT-1, which is sponsored by PECO witness Michael J. Trzaska and discussed in Mr. Trzaska's direct testimony (PECO Statement No. 3). The total distribution revenue requirement for the FPFTY is $2.102 billion (PECO Exhibit TJJ-1, line 64) excluding costs

recovered under PECO's Generation Supply Adjustment ("GSA")[1] and Transmission Service Charge ("TSC")[2] and $3.373 billion (PECO Exhibit TJJ-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 COSS were also obtained from PECO Exhibit MJT-1.

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

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

1. The current tariff rates produce the net income by rate class shown on line 16 of PECO Exhibit TJJ-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	5.14%	1.16
RH	2.58%	0.59
GS	4.08%	0.92
PD	3.36%	0.76

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

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

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

HT	3.93%	0.89
EP	2.51%	0.57
Lighting	5.86%	1.33
Average	4.41%	

2. PECO's total distribution revenue requirement for the FPFTY has been allocated or assigned among the rate classes based on the results of the COSS. The results of the COSS are summarized on pages 1-3 of PECO Exhibit TJJ-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 TJJ-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 TJJ-1. While the summary on pages 1-3 of PECO Exhibit TJJ-1 shows the rate increases or (decreases) necessary to move each class to the system average rate of return, the Company is not proposing rates that will take all classes to their indicated cost of service at this time, as explained in the direct testimony of Joseph A. Bisti in PECO Statement No. 7.

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

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

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

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

A. The central element in performing a COSS is the determination of allocation factors based on causal relationships between, on the one hand, customer demands, load profiles, and usage characteristics, and, on the other hand, the costs incurred by the Company to meet customers' service requirements imposed by those demands, load profiles, and usage characteristics. The primary goals in selecting allocation factors are: (1) the appropriate recognition of cost causality; (2) the stability of study methods and their consistent application over time, so that trends in the direction of class revenues relative to cost of service can be discerned properly from case to case; and (3) completeness, such that the COSS captures all the costs that each class imposes on the distribution system.

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

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

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

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

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

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

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

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

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

1. Connect all customers to the grid;

2. Deliver sufficient electricity to meet the aggregate peak demand for electricity of all delivery customers whenever those peaks occur; and

3. Ensure that electricity is delivered to customers safely and reliably throughout the year.

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

The PECO COSS I prepared was performed using the 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 COSS, accelerates computations, and develops appropriate documentation. The Model uses a three-step process to allocate or assign costs to rate classes, in accordance with general cost of service principles. These three steps consist of: (1) functionalizing rate base and costs to determine the particular rate schedules that should share responsibility for each of those assets and costs; (2) classifying functionalized costs into demand-related, energy-related, and customer-related cost categories to facilitate allocating such costs to rate

schedules in accordance with identifiable characteristics; and (3) allocating the functionalized, classified costs among rate classes. The Model provides functionalized, classified cost information by rate class, develops unbundled revenue requirements by functional classification and in total for each rate class, and calculates unit costs.

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

A. The COSS includes the following functions:

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

Transmission: This function includes costs associated with the Company's bulk transmission system, which is designed to move power from generation sources to the primary distribution system and operates at voltages of 69 kV and above. These costs are generally recovered in the TSC and the Non-Bypassable Transmission Rider ("NBT").[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

[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.

kV or 13 kV and from 34 kV to 13 kV, conductors operating primarily at voltages between 13 kV and 34 kV, and related assets. This includes some facilities operating at voltages of 69 kV and above that are distribution facilities.

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

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

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

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

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

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

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

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

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

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

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

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

Demand-related or capacity-related costs are those expenditures associated with plant that is designed, installed, and operated to meet peak usage. Distribution assets are designed to meet the peak loads of the customers they serve at a

localized level. Such localized loads exhibit far less diversity than the aggregation of such localized loads that occurs at the bulk transmission and generation levels. Accordingly, the costs of demand-related distribution assets are allocated among the rate classes based upon their respective class NCP demands (i.e., the peak electricity demand of each rate class, not necessarily coincident with each other or with the system peak).

18. 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.

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

A. In the class allocation step, costs that have been functionalized and classified are allocated among the rate classes based on appropriate causal relationships. The allocation phase takes into account the design of the utility system and how it is operated, cost data derived from the utility's accounting records, and usage and load data both for the system overall and for specific customer classes. Based on

analyses of the relationship between costs and the factors driving the need to incur such costs, each component of the revenue requirement is either directly assigned to a rate class or an allocator is selected to apportion that component among rate classes.

20. 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.

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

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

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

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

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

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

A. The total rate base amount employed in the PECO COSS is $8.856 billion (PECO Exhibit TJJ-1, line 103) and is derived from PECO Exhibit MJT-1, page 1.

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

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

- Intangible plant
- Distribution plant
- General plant

- Depreciation reserve
- Other rate base items

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

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

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

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

- Land and land rights, stations, and structures and improvements were functionalized to Primary HT, classified as demand, and allocated among the rate classes based on their respective class NCP demands at the Primary HT level.
- Poles, towers and fixtures, overhead conductors and devices, underground conduit, and underground conductors and devices were

functionalized between Primary HT/Primary, on one hand, and Secondary Distribution, on the other, based on a detailed study of the respective costs, as shown in PECO Exhibit TJJ-7 at page 4. The Primary HT/Primary portion was split between Primary HT and Primary based on a study of the respective wire miles of conductors in each function (*see* PECO Exhibit TJJ-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 TJJ-7, p. 15). Costs identified as Secondary Distribution were classified as customer-related and allocated based on the number of customer locations served.

- Line transformers were functionalized to Secondary Distribution and allocated among the rate classes based on NCP demands at secondary voltage (*see* PECO Exhibit TJJ-7, p. 15).
- Services connect individual customers to the system and, therefore, were functionalized to their own category, classified as customer-related, and allocated based on the estimated total replacement cost of all services in each rate class (*see* PECO Exhibit TJJ-7, p. 6). The total replacement cost of services for a rate class was estimated by multiplying the estimated replacement cost of a single service for a member of the class by the number of customer locations in the class.

- Meters were functionalized to their own category, classified as customer-related, and directly assigned based on the cost of new AMI meters installed pursuant to PECO's Smart Meter Universal Deployment Plan, which was approved by the Pennsylvania Public Utility Commission ("Commission") on August 15, 2013 at Docket No. M-2009-2173944 (*see* PECO Exhibit TJJ-7, p. 7).
- Street lighting and signal systems were functionalized to Customer Other, classified as customer-related, and directly assigned to Lighting.

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

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

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

- Materials and supplies were functionalized, classified, and allocated among rate classes in proportion to plant in service.
- Accumulated deferred income taxes were primarily functionalized, classified, and allocated among rate classes in proportion to plant in service.
- Customer deposits were directly assigned to rate classes based on information provided by Mr. Trzaska (included in PECO Exhibit TJJ-7, p. 8).
- Common plant consists of assets similar to those customarily found in General Plant and, therefore, was functionalized, classified, and allocated among rate classes based on the direct labor component of operating expenses.
- Customer advances were functionalized to Distribution and Secondary Distribution, classified as demand and customer-related, and allocated among the rate classes in the same proportion as Distribution and Secondary Distribution assets.
- Working capital represents PECO's need for cash to keep the business running until revenues are collected to pay the costs of providing service. Working capital was calculated based on the results of the lead-lag study prepared by Mr. Trzaska and described in PECO Statement No. 3. Also, working capital was directly assigned to Energy and Transmission based on the results of that lead-lag study. The balance of working capital was functionalized, classified, and

allocated to each rate class using methodologies consistent with the nature of the underlying cost.

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

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

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

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

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

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

A. PECO's distribution system consists principally of substations; poles, towers and fixtures; overhead and underground conductors and related equipment; meters; line transformers; outdoor lighting plant; and other miscellaneous assets. Operating and maintenance expenses were analyzed to determine the assets they were incurred to operate or maintain and, therefore, were functionalized, classified, and allocated among rate classes in the same manner as the assets to which they relate. The COSS also includes costs of purchased power and transmission costs paid to PJM that are recovered through the GSA, TSC, and NBT charges. Purchased power costs were functionalized as Energy, classified as energy-related, and allocated based on projected default service prices and MWh of generation energy revenue in the budget. Transmission-related costs were functionalized as Transmission and assigned among rate classes based on their contributions to the single coincident peak. In addition to the expenses of operating and maintaining PECO's distribution system, distribution expenses include the following:

- **Customer-installation expenses**: These expenses relate to field investigations, high-bill complaints, and potential and actual energy theft, and were allocated based on number of customers.
- **Miscellaneous distribution expenses and rents**: These expenses relate to information technology ("IT") and other expenses associated

with all distribution assets. Accordingly, they were functionalized, classified, and allocated among rate classes in proportion to total distribution plant.

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

A. Customer accounts and customer service expenses primarily include meter-reading expenses, customer records and collection expenses, uncollectible accounts expense, miscellaneous customer accounts expense, customer-assistance expense, and sales expense. These costs were functionalized to Customer Accounts, classified as customer-related, and allocated as follows:

- **Meter reading expenses** have been supplanted by the new AMI system expenses except for some minor expenses. Costs are allocated based on the cost of meters.

- **Customer records and collection expenses** relate to billing, call center operations, payment processing, arrearage recoveries, support for administration of PECO's CAP program, and termination and restoration of service. The account was analyzed in detail, discrete functions were identified, and expenses related to each function were allocated among rate classes using an appropriate allocation factor (*see* PECO Exhibit TJJ-7, p. 9). For example, expenses incurred for billing activities were allocated based on number of bills, and call center costs

were allocated based on number of customers. A single customer allocation could not be used because some costs are specific to residential customers while others are specific to commercial and industrial customers; therefore, a weighted allocator, based upon the analysis discussed above, was used for this account.

- **Uncollectible accounts expense**, or bad debt expense, was allocated among rate classes based on the Company's experience over a historic three-year period (2021-2023) (*see* PECO Exhibit TJJ-7, p. 12).

- **Miscellaneous customer accounts expense** includes IT support for the other customer account functions and was allocated among rate classes based on number of customers.

- **Customer assistance expense** includes expenses incurred for the Low-Income Usage Reduction Program and marketing. Costs specific to the residential class were allocated to rates R and RH based on number of customers. Costs specific to the C&I classes were allocated to rates GS, PD and HT based on number of customers on the applicable rates. General marketing costs were allocated based on number of customers (*see* PECO Exhibit TJJ-7, p. 10).

- **Informational advertising expense** includes the cost of activities that primarily convey information as to what the utility suggests customers should do in utilizing electric service to protect health and safety, to encourage environmental protection, to utilize their electric equipment

safely and economically, or to conserve electric energy, and was allocated to customer classes based on number of customers.

- **Sales expenses** include expenses incurred in activities, which promote or retain the use of utility distribution services by present and prospective customers, and was allocated to rates GS, PD, and HT customers based on customer energy consumption.

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

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

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

- **Property insurance costs** were functionalized, classified, and allocated among rate classes in the same ratio as distribution and general plant in service.

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

- **Certain costs related to electric vehicle incentives,** as described more fully in the testimony of Company witness Steven J. DeMott, were functionalized, classified and allocated among rate classes based on the number of Commercial and Industrial customers.

- **Costs related to the reallocation of transit charging costs,** as described more fully in the testimony of Mr. DeMott and at PECO Exhibit TJJ-7, page 17, were functionalized, classified and allocated among rate classes based on the difference between the allocation in PECO's prior rate case and Commercial and Industrial customers in the current case.

- **Maintenance of general plant expenses** were functionalized, classified, and allocated among rate classes in the same ratio as general plant in service.

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

A. Depreciation expense was derived from PECO Exhibit CF-3, which is sponsored by PECO witness Caroline Fulginiti, as well as PECO Exhibit MJT-1, which show depreciation expense by plant account. The depreciation reserve was obtained from the same sources. Both the depreciation expense and the depreciation reserve were functionalized, classified, and allocated among rate classes in the same ratio as the plant account to which they relate.

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

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

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

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

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

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

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

A. Distribution revenue at present rates is shown in the proof of revenues set forth in PECO Exhibit JAB-4. 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 TJJ-1.

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

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

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

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

Decommissioning payments in the FPFTY represent PECO's transfer to 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, LLC 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, except for connection charges and returned check fees, which were allocated based on number of customers.

IV. DEVELOPMENT OF RATE CLASS REVENUE REQUIREMENT

36. 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. Trzaska to compute the overall revenue requirement for the FPFTY. Thus, the revenue requirements for each rate class are the sum of that class's allocated operating expenses, depreciation expense, general taxes, return on rate base, and income tax expense. Return on rate base for each rate class was computed by multiplying the rate class's rate base by the proposed system average rate of return. Income taxes included in the

[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 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).

revenue requirement for each rate class were computed directly by grossing up the required non-debt return on rate base for the class at the applicable statutory income tax rates. PECO Exhibit TJJ-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 TJJ-1, line 69, shows the portion of the total revenue requirements PECO proposes to collect in distribution rates.

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

A. The increase or decrease needed for each rate class was calculated by comparing the revenue requirements for each rate class to the forecasted revenue at present rates for that class for the FPFTY. This is the same method used by Mr. Trzaska in PECO Exhibit MJT-1, Schedule A-1, with respect to the overall revenue requirement and revenue deficiency. The increases in rate class revenue needed to produce a rate of return equal to the Company's proposed overall rate of return are shown in PECO Exhibit TJJ-1 at line 120, which total $463.6 million. The increases in class distribution revenue are shown on line 70, which total $463.4 million. The decrease in transmission revenue under the TSC are shown on line 95, which total ($0.1) million on a net basis, and the increase in purchased power revenue under the GSA of $0.3 million is shown on line 83. In addition, forfeited discounts are expected to increase by $1.4 million as a result of the increase in distribution rates.

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

38. Q. Please describe what is shown on PECO Exhibit TJJ-1.

A. PECO Exhibit TJJ-1, which sets forth the substance of the COSS, compares the revenue at current rates by rate class to the revenue requirement allocated on a cost-of-service basis to each rate class. 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, respectively) 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's 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 109 shows taxes other than income taxes excluding the gross receipts tax, 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 (excluding forfeited discounts on the increased revenue). 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 83 shows the

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

39. Q. What information is shown on PECO Exhibit TJJ-2?

A. PECO Exhibit TJJ-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 16 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 17 to 31 of the exhibit.

40. Q. Please describe the information contained in PECO Exhibit TJJ-3.

A. PECO Exhibit TJJ-3 contains the COSS by functional category and classification. The summary appears on pages 1 to 6 and the account-by-account allocation to functional category and classification is provided on pages 7 to 32. Pages 33 to 62 of this exhibit provide the external and internal allocators used for the exhibit.

41. Q. Please describe what is shown in PECO Exhibit TJJ-4.

A. PECO Exhibit TJJ-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.

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

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

In Pennsylvania, the costs typically considered in developing residential customer charges exclude allocated portions of the distribution system. Therefore, PECO Exhibit TJJ-5 excludes the component shown on PECO Exhibit TJJ-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.

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

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

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

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

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

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

Mr. Bisti uses these costs to determine the appropriate charge for the NSR as discussed in PECO Statement No. 7.

45. Q. Please describe the information shown on PECO Exhibit TJJ-7.

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

Index (page 1) - Table of External Allocators

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

Summary of External Allocator Values (page 3) - Functionalization

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

conductor split, and the functional split for underground conduit follows underground conductor split.

Conductors-Primary Splits (page 5) - Allocates the cost of Overhead Conductors operating at primary voltage between Primary HT and Primary based on the wire miles of those conductors as of December 31, 2023. 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 2020-2023. PECO does not account for services separately and, therefore, has used estimated replacement cost to allocate the account to the classes of service.

Meter Costs (page 7) - Meter costs were allocated among rate classes based on the average cost of meters of each type for each rate class, as determined from the Company's records as of December 2023. Meter costs include both materials and labor.

Customer Deposits (page 8) - Allocates FPFTY customer deposits based on the 13-month average customer deposit balances for each class for the period from December 2022 through December 2023.

Account 903 Allocator (page 9) - Allocates costs associated with each activity recorded in Account 903 – Customer Records and Collection Expense for 2022

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 12 summarizes the costs by rate class. The weighted allocators are shown on row 13. The separate allocations are necessary because some costs are only applicable to specific rate classes.

Account 908 Allocator (page 10) - Allocates the costs of each activity recorded in Account 908 – Customer Assistance for 2022 using an appropriate external allocator. Rows 1-5 list each activity, the cost of the activity and the allocator assigned to it. Row 6 summarizes the costs by rate class. The allocators are on row 7.

Account 912 and 916 Allocator (page 11) - Allocates the cost of each activity recorded in Accounts 912 – Demonstrating and Selling Expense and 916 – Miscellaneous Sales Expense for 2022 using an appropriate external allocator. Each activity, the costs of the activity, and the allocator assigned to each is shown in a separate row. Row 2 summarizes the costs by rate class. The weighted allocators are shown on row 3.

Write-Offs (page 12) - Computes the Write-Off allocators using net charge-offs for 2021 through 2023.

Over 60-Day (page 13) - Computes the Over 60-Day allocators. The column "Over 60-Day Allocator" shows the percentage of PECO's total electric accounts receivable outstanding for more than two months for each rate class at each month-end from January 2022 through December 2022.

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

Demand Allocators (page 15) - Computes the demand allocators used in the COSS based on data from October 2022 through September 2023.

MWh Deliveries at Generation (page 16) - Computes MWh at the different rate classes based on projected 2025 sales at the meter and appropriate loss factors for each rate class. The class loss factors are the same as those set forth in the Company's Electric Generation Supplier Coordination Tariff.

Transit Charging Allocator (page 17) – Computes the allocator used to reallocate $1.0 million of transit charging funds received in the prior rate case to the customer classes that will benefit from the intended use of the funds as described in the direct testimony of Mr. DeMott (PECO Statement No. 10).

Customer and Location-Based Allocators (page 2) - The demand-based, customer-based and location-based allocators are shown on page 2 at lines 8-15. The location-based allocator (Location Secondary) shown on line 15 was modified for street lighting to reflect 25% of each of the total locations for the Lighting class. This adjustment was made to more accurately reflect cost causation. Street lights are generally located where there are existing Company facilities serving other load. In some cases, street lights were installed after the grid was in place and, therefore, did not contribute to the need for poles, conductors, or conduit to be installed. However, that is not always the case and, in some instances, the system was built out for the lights, for example, as on some

bridges and roads. Counting each location as a separate customer would allocate too much cost to street lighting. On the other hand, not counting any lighting locations as customers would understate the costs allocated to street lighting. Even where the system was in place before street lights were installed, it is appropriate to allocate some cost to the Lighting class because the service is benefiting from the poles, conductors, and conduit. I have, therefore, applied a 25% factor to the number of locations to allocate a reasonable level of cost to the Lighting class.

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

A. In the cost-of-service summary there is a section for purchased power and a section for transmission. These sections are used to derive the unbundled cash working capital requirement that is recovered in the GSA and the TSC. The revenue requirement associated with cash working capital is used to develop a rate for the GSA and TSC. The total revenue requirement used to develop the rate is the operating income consisting of return, income taxes, and the associated gross receipts tax. I am providing PECO Exhibit TJJ-8 to show the calculation of the unbundled cash working capital rate for the GSA. PECO Exhibit TJJ-9 provides the calculation of the unbundled cash working capital rate for the TSC. The rate developed in PECO Exhibit TJJ-8 of $0.00035 per kWh will replace the rate of $0.00021 per kWh currently in the GSA. The rate developed in PECO Exhibit TJJ-9 of $274 per MW-year will replace the current rate of $278 per MW-year in the TSC.

VI. CONCLUSION

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

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

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

A. Yes, it does.

PECO Exhibit TJJ-1:

Summary of Cost-of-Service Study Results

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
	1	**SUMMARY AT PRESENT RATES**									
		DEVELOPMENT OF DISTRIBUTION RETURN									
		OPER□TI□G RE□E□□E									
		□a□e□of E□e□tri□it□- Ba□e	□CH RBC□□□□ □□	1□□□□□1□□	□□□□1□□	1□□□□□1	□□□□01□	□□□□□	1□□□□□□	□□0□□	□□□0□□
		De□o□ □i□□io□i□g Re□e□□e□	□CH RBC□□□□ □□	□□□□1□□	□1□□1□□	□□□□□	□□□□□	□□□□	□1□□□□□	□□1□	□□0□
		Other O□erati□g Re□e□□e	□CH RBC□□□□ □□	□□□□□□	□0□□□□	□□□1□	□□□0□	1□□	□□00□	□□□	□□□
		TOT□□ OPER□TI□G RE□E□□E		1□□□□□1□□	□□□□1□□	1□□□□□1	□□□□□□□	□□□1□	1□1□□□	□□□□□	□□□□□□
		OPER□TI□G EXPE□□E□									
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	11	De□re□iatio□a□d □□orti□atio□ Ex□e□□e	□CH D□□□□ □0	□□□□□□	1□□□0□□	□□□□□□	□□□1□□	1□□□□	□1□□□□	1□□□□	□□□□□
	1□	Taxe□Other Tha□ I□□o□e Taxe□-Ge□era□	□CH TO□□□□ 11	□□□□□□	1□□□□0	□□□□□	□□□□1	1□□	□□□□□	1□□	□□1
	1□	Taxe□Other Tha□ I□□o□e Taxe□-Di□trib□tio□GRT	□CH TO□□□□ □□	□1□□□□	□□□1□□	10□1□□	1□□□□□	□□0	10□□□□	□□1□	1□□□□
	1□	I□□o□e Taxe□	□CH TI□□□□ □□	□1□□□1□□	□□□□□□	□10□□□□□	□□□□0□□	□□□□□□	□□□□0□□	□□□□□□	□□□1
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	1□	**OPERATING INCOME (RETURN)**		□□□□□□□	□□1□□□□	□0□□0□	□□□□□□□	1□□0□	□□□□00	1□□□□	□□□□□
	1□										
	1□	**DEVELOPMENT OF RATE BASE**									
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	□0	□e□□□ □□□□□ □ated De□re□iatio□	□CH RBD□□□□ □□	□□□□□□□□□□	1□1□□□□00	□□□□□□1	□□□□□□0	11□1□□	□□□□00□	1□□1□1	□□□□□1
	□1	P□□□□ Rate Ba□e □dditio□□	□CH RBO□□□□ □0	□□□□0□□	□□□□1□□	□□0□□□□	1□□□□01	□□0□0	□□□0□□	□□□□□	□□1□0
	□□	□e□□□ Rate Ba□e Ded□tio□□	□CH RBO□□□□ □□	□□□□□□□	□□□□□□□	1□□0□□	□0□□□□1	□□□□□	1□□□1□	□□□□□	1□□□1□
	□□	**TOTAL DISTRIBUTION RATE BASE**	□CH RBO□□□□ □□	□□□00□□□□	□□□0□□□□□	1□1□1□□□1	1□□□□□□□□	□□□□□0	1□1□□□□□1	□□□□10	1□□□□1□
	□□										
	□□	**DISTRIBUTION RATE OF RETURN (PRESENT)**		□□□1□	□□1□□	□□□□□	□□0□□	□□□□□	□□□□□	□□□1□	□□□□□
	□□	**DISTRIBUTION INDEX RATE OF RETURN (PRESENT)**		1□00	1□1□	0□□□	0□□□	0□□□	0□□□	0□□□	1□□□
	□□										
	□□	**DEVELOPMENT OF PURCHASED POWER RETURN**									
	□□	P□r□ha□ed E□e□tri□Re□e□□e□	□CH RBC□□□□ □□	1□0□1□□00	□□□□□0□	1□0□□□□	1□□□□□□	1□0□□	□0□□□0	0	□□□
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	□1	P□r□ha□ed Po□er GRT Ex□e□□e	□CH TO□□□□ □1	□□□□01	□0□□□□	10□□□□	□□□□1	□□	□□00□	0	□0
	□□	P□r□ha□ed Po□er I□□o□e Taxe□		□0□	□□□□	1□□	1□□	1	□□	0	1
	□□	P□r□ha□ed Po□er O□erati□g I□□o□e		□□□□□	□□1□□	□□1	□□□□	□	1□1	0	□
	□□	Rate Ba□e - P□r□ha□ed P□r Ca□h □ or□i□g Ca□ita□	□CH RBC□□□□ □□	□□□1□□	□□□0□□	□□□□□	□□□□□	□□	□□1□□	0	□□
	□□	**PURCHASED POWER RATE OF RETURN (PRESENT)**		□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	0□00□	□□□□□
	□□										
	□□	**DEVELOPMENT OF TRANSMISSON RETURN**									
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	□□	Tra□□□ i□□io□ O□M Ex□e□□e	□CH E□□□□ □□	1□□□□0□	10□□□□□	□□□□□□□	□□1□□1□	□□1□	□□11□	□□□□	□□
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	□□	**TRANSMISSION RATE OF RETURN (PRESENT)**		□□□1□	11□□□□	□0□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□
	□□										
	□□	**TOTAL OPERATING INCOME (RETURN)**		□□□□□1□	□□□□□1□	□1□□01	□□□□□□	1□□1□	□□□□□□	1□□□1	□□□□□
	□□	**TOTAL RATE BASE**		□□□□□□□□□	□□□□□□□□□	1□1□□□□□□	1□□0□□□□0	□□□0□□	1□1□□□□□	□□□□□□	1□□□□□□
	□□	**COMPOSITE RATE OF RETURN @ CURRENT RATES**		□□□□□	□□1□□	□□□□□	□□0□□	□□□□□	□□□□□	□□□□□	□□□□□
	□□										
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
	1	EQUALIZED RETURN AT PROPOSED ROR OF 7.98%									
		DEVELOPMENT OF DISTRIBUTION RETURN (EQUALIZED RATE)									
		RATE BASE	CH								
		RETURN (RATE BASE * 7.98% ROR)									
		PLUS:									
		OPERATING EXPENSES									
		O eratio a d Mai te a e Ex e e	C C TED								
		De re iatio a d ortiatio Ex e e	CH 11								
		Taxe Other Tha I o e Taxe -Ge era	CH 1								
	0	Taxe Other Tha I o e Taxe -Di trib tio GRT	C C TED								
	1	tate a d Federa I o e Taxe	C C TED								
		TOTAL OPERATING EXPENSES									
		EQUALS TOTAL COST OF SERVICE									
		LESS:									
		De o i io i g Re e e	CH								
		Other O erati g Re e e	C C TED								
		EQUALS:									
		DISTRIBUTION BASE RATE SALES @ EQUALIZED ROR 7.98%									
	0	Di trib tio Co I rea e itho t Forfeited Di o t									
	1	TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE									
		REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISCOUNT(%)									
		DEVELOPMENT OF PURCH. POWER RETURN (EQUALIZED RATE)									
		RATE BASE (CWC)	CH							0	
		RETURN (RATE BASE * 7.98% ROR)								0	
		PLUS:									
		OPERATING EXPENSES									
		P r ha ed Po er O M Ex e e	CH 0							0	
	0	P r ha ed Po er I o e Taxe	C C TED							0	1
	1	P r ha ed Po er GRT Ex e e	C C TED							0	0
		EQUALS TOTAL PURCHASED POWER COST OF SERVICE								0	
		TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE						0		0	0
		REVENUE INCREASE TO DISTRIBUTION REVENUES (%)		0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
										0.00	
		DEVELOPMENT OF TRANSMISSION RETURN (EQUALIZED RATE)									
		RATE BASE (CWC)	CH								
		RETURN (RATE BASE * 7.98% ROR)									1
		PLUS:									
	0	OPERATING EXPENSES									
	1	Tra i io O M Ex e e	CH								
		Tra i io I o e Taxe	C C TED		1	1					0
		Tra i io GRT Ex e e	C C TED								
		EQUALS TOTAL TRANSMISSION COST OF SERVICE									
		TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE									0
		REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)		-0.0	-0.1	-0.0	0.1	0.0	0.0	0.0	0.0
		TOTAL INCREASE (DECREASE) REQUIRED									
	100										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
	101	**EQUALIZED RETURN AT PROPOSED ROR OF 7.98%**									
	10	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**									
	10	**RATE BASE**	C TED								
	10	**RETURN (RATE BASE * 7.98% ROR)**									
	10	**PLUS:**									
	10	**OPERATING EXPENSES**									
	10	Operation and Maintenance Expense	C TED								
	10	Depreciation and Amortization Expense	CH								
	10	Taxes Other Than Income Taxes-General	CH								
	110	Taxes Other Than Income Taxes-GRT	C TED								
	111	State and Federal Income Taxes	C TED								
	11	**TOTAL OPERATING EXPENSES**									
	11										
	11	**EQUALS TOTAL COST OF SERVICE**									
	11	**LESS:**									
	11	Decommissioning Revenue	CH								
	11	Other Operating Revenue	CH								
	11	**EQUALS:**									
	11	**OVERALL BASE RATES @ EQUALIZED ROR 7.98%**									
	10	**COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISCOUNT**									
	1 1	**TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE**									
	1										
	1										
	1

PECO Exhibit TJJ-2:

Total Class Allocation - Revenue Requirement By Rate Class

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
	1	**SUMMARY AT PRESENT RATES**									
		DEVELOPMENT OF DISTRIBUTION RETURN									
		OPER□TI□G RE□E□□E									
		□a□e□of E□e□tri□it□- Ba□e	□CH RBC□□□□ □□								
		De□o□ □i□□io□i□g Re□e□□e□	□CH RBC□□□□ □□								
		Other O□erati□g Re□e□□e	□CH RBC□□□□ □□								
		TOT□□ OPER□TI□G RE□E□□E									
		OPER□TI□G EXPE□□E□									
	10	O□eratio□a□d Mai□te□a□□e Ex□e□□e	□CH E□□□□ □□								
	11	De□re□iatio□a□d □□orti□atio□ Ex□e□□e	□CH D□□□□ □0								
	1□	Taxe□ Other Tha□ I□□o□e Taxe□-Ge□era□	□CH TO□□□□ 11								
	1□	Taxe□ Other Tha□ I□□o□e Taxe□-Di□trib□tio□ GRT	□CH TO□□□□ □□								
	1□	I□□o□e Taxe□	□CH TI□□□□ □□								
	1□	TOT□□ OPER□TI□G EXPE□□E□									
	1□	**OPERATING INCOME (RETURN)**									
	1□										
	1□	**DEVELOPMENT OF RATE BASE**									
	1□	E□e□tri□ P□a□t i□ □er□i□e	□CH RBP□□□□ □□								
	□0	□e□□□ □□□□□ □ated De□re□iatio□	□CH RBD□□□□ □□								
	□1	P□□□□ Rate Ba□e □dditio□□	□CH RBO□□□□ □0								
	□□	□e□□□ Rate Ba□e Ded□□tio□□	□CH RBO□□□□ □□								
	□□	**TOTAL DISTRIBUTION RATE BASE**	□CH RBO□□□□ □□								
	□□										
	□□	**DISTRIBUTION RATE OF RETURN (PRESENT)**									
	□□	**DISTRIBUTION INDEX RATE OF RETURN (PRESENT)**									
	□□										
	□□	**DEVELOPMENT OF PURCHASED POWER RETURN**									
	□□	P□r□ha□ed E□e□tri□ Re□e□□e□	□CH RBC□□□□ □□								
	□0	P□r□ha□ed Po□er O□M Ex□e□□e	□CH E□□□□ □1								
	□1	P□r□ha□ed Po□er GRT Ex□e□□e	□CH TO□□□□ □1								
	□□	P□r□ha□ed Po□er I□□o□e Taxe□									
	□□	P□r□ha□ed Po□er O□erati□g I□□o□e									
	□□	Rate Ba□e - P□r□ha□ed P□r Ca□h □ or□i□g Ca□ita□	□CH RBC□□□□ □□								
	□□	**PURCHASED POWER RATE OF RETURN (PRESENT)**									
	□□										
	□□	**DEVELOPMENT OF TRANSMISSON RETURN**									
	□□	Tra□□□ i□□io□ Re□e□□e□	□CH RBC□□□□ □□								
	□□	Tra□□□ i□□io□ O□M Ex□e□□e	□CH E□□□□ □□								
	□0	Tra□□□ i□□io□ GRT Ex□e□□e	□CH TO□□□□ □□								
	□1	Tra□□□ i□□io□ I□□o□e Taxe□									
	□□	Tra□□□ i□□io□ O□erati□g I□□o□e									
	□□	Rate Ba□e - Tra□□□ i□□io□ Ca□h □ or□i□g Ca□ita□	□CH RBO□□□□ □□								
	□□	**TRANSMISSION RATE OF RETURN (PRESENT)**									
	□□										
	□□	**TOTAL OPERATING INCOME (RETURN)**									
	□□	**TOTAL RATE BASE**									
	□□	**COMPOSITE RATE OF RETURN @ CURRENT RATES**									
	□□										
	□0										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
	1	EQUALIZED RETURN AT PROPOSED ROR OF 7.98%									
		DEVELOPMENT OF DISTRIBUTION RETURN (EQUALIZED RATE)									
		RATE BASE	CH								
		RETURN (RATE BASE * 7.98% ROR)									
		PLUS:									
		OPERATING EXPENSES									
		O eratio a d Mai te a e Ex e e	C C TED								
		De re iatio a d ortiatio Ex e e	CH 11								
		Taxe Other Tha I o e Taxe -Ge era	CH 1								
	0	Taxe Other Tha I o e Taxe -Di trib tio GRT	C C TED								
	1	tate a d Federa I o e Taxe	C C TED								
		TOTAL OPERATING EXPENSES									
		EQUALS TOTAL COST OF SERVICE									
		LESS:									
		De o i io ig Re e e	CH								
		Other O erati g Re e e	C C TED								
		EQUALS:									
		DISTRIBUTION BASE RATE SALES @ EQUALIZED ROR 7.98%									
	0	Di trib tio Co I rea e itho t Forfeited Di o t									
	1	TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE									
		REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISCOUNT(%)									
		DEVELOPMENT OF PURCH. POWER RETURN (EQUALIZED RATE)									
		RATE BASE (CWC)	CH							0	
		RETURN (RATE BASE * 7.98% ROR)								0	
		PLUS:									
		OPERATING EXPENSES									
		P r ha ed Po er O M Ex e e	CH 0							0	
	0	P r ha ed Po er I o e Taxe	C C TED							0	1
	1	P r ha ed Po er GRT Ex e e	C C TED							0	0
		EQUALS TOTAL PURCHASED POWER COST OF SERVICE								0	
		TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE						0		0	0
		REVENUE INCREASE TO DISTRIBUTION REVENUES (%)		0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
										0.00	
		DEVELOPMENT OF TRANSMISSION RETURN (EQUALIZED RATE)									
		RATE BASE (CWC)	CH								
		RETURN (RATE BASE * 7.98% ROR)									1
		PLUS:									
	0	OPERATING EXPENSES									
	1	Tra i io O M Ex e e	CH								
		Tra i io I o e Taxe	C C TED		1	1					0
		Tra i io GRT Ex e e	C C TED								
		EQUALS TOTAL TRANSMISSION COST OF SERVICE									
		TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE			11	10	0		1		0
		REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)		-0.0	-0.1	-0.0	0.1	0.0	0.0	0.0	0.0
		TOTAL INCREASE (DECREASE) REQUIRED									
	100										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
	101	**EQUALIZED RETURN AT PROPOSED ROR OF 7.98%**									
	10	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**									
	10	**RATE BASE**	C C TED								
	10	**RETURN (RATE BASE * 7.98% ROR)**									
	10	**PLUS:**									
	10	**OPERATING EXPENSES**									
	10	O eratio a d Mai te a e Ex e e	C C TED								
	10	De re iatio a d orti atio Ex e e	CH								
	10	Taxe Other Tha I o e Taxe -Ge era	CH								
	110	Taxe Other Tha I o e Taxe -GRT	C C TED								
	111	tate a d Federa I o e Taxe	C C TED								
	11	**TOTAL OPERATING EXPENSES**									
	11										
	11	**EQUALS TOTAL COST OF SERVICE**									
	11	**LESS:**									
	11	De o i io i g Re e e	CH								
	11	Other O erati g Re e e	CH								
	11	**EQUALS:**									
	11	**OVERALL BASE RATES @ EQUALIZED ROR 7.98%**									
	10	**COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISCOUNT**									
	1 1	**TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE**									
	1										
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	1										
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
RBP	1	**DEVELOPMENT OF RATE BASE**									
RBP		**ELECTRIC PLANT IN SERVICE**									
RBP		I□T□□GIB□E P□□□T									
RBP		□0□-□0□-Fra□hi□e a□d □o□□e□t□ □ Mi□□ I□ta□g□P□a□t	TDP□T	1□□□□□□	□□□□00	1□□□1□	□□□□□□	□□□	1□□□□1	□0□	□□□□0
RBP		□0□-	C□□TRE□	0	0	0	0	0	0	0	0
RBP		□0□-	C□□T	0	0	0	0	0	0	0	0
RBP		□0□-□MI P□a□t	CMETER□	□□□1□	□□□□□	□□1	□□1	□□	□1□	□	0
RBP		TOT□□ I□T□□GIB□E P□□□T		1□□□□□□	□□□□□□	1□□1□□	□□□□□□	□□□	1□□□□□	□1□	□□□□0
RBP											
RBP	10	TR□□□MI□□IO□ P□□□T									
RBP	11	□□0-□□□ □□□o□□t□	DTR□□	0	0	0	0	0	0	0	0
RBP	1□	□□1- Tra□□□ i□□io□ Re□ated P□a□t	DTR□□	0	0	0	0	0	0	0	0
RBP	1□	TOT□□ TR□□□MI□□IO□ P□□□T		0	0	0	0	0	0	0	0
RBP	1□										
RBP	1□	DI□TRIB□TIO□ P□□□T									
RBP	1□	□□0-□a□d □ □a□d Right□	DDI□PHT	□□□1□□	□1□0□1	□□□0□	10□□□□	□□□	1□□1□□	□□□	□□□
RBP	1□	□□1-□tr□t□re□□ I□ □ro□e□ e□t□	DDI□PHT	□□□□□□	□□□□□□	□□□□00	□0□□□□	1□□□□	□□□□□□	□□□□□	1□□□□
RBP	1□	□□□-□tatio□ E□□i□□ e□t	DDI□PHT	1□□0□□□0	□□□□□□	1□□□□0□	□□□□1□□	10□□□□	□□□□□00	1□□0□□	□□□□□
RBP	1□	□□□-Po□ē□To□er□ □ Fixt□re□									
RBP	□0	Pri□ ar□HT	DDI□PHT	□□0□1□□	□□□□□□0	□□□0□□	1□□□□□□	□□0□□	1□0□□□	□□□□1	□□□□□
RBP	□1	Pri□ ar□	DDI□TPO□	□□□□00□	□0□□□00	□□□□□□	10□□□□	□□□0□	0	0	□□□□□
RBP	□□	□e□o□dar□	CDI□T□O□C	□1□□□00	□1□□□□1	□□□□□0	□□□0□□	0	0	0	1□□1□□
RBP	□□	Tota□□□o□□t □□□		1□□□□□□0□	□□□□□□1	□0□□□□□	□□□□□□	□□□□□	1□0□□□	□□□□1	1□□□□
RBP	□□	□□□-O□erhead Co□d□□tor□ □ De□i□e□									
RBP	□□	Pri□ ar□HT	DDI□PHT	1□101□□1□	□□□□□□0	1□0□□□□	□1□□□□□	□□0□□	□□□□□□□	1□□1□□	□□□□□
RBP	□□	Pri□ ar□	DDI□TPO□	□1□□□□□	□□1□□□□	10□□□□	1□□□□□	□□□□□	0	0	□□□0□
RBP	□□	□e□o□dar□	CDI□T□□□C	□□□□0□□	□0□□□□□	□□□1□□	□□□1□□	0	0	0	□0□□□0
RBP	□□	Tota□□□o□□t □□□		□□□□□□0□	1□□□□□□□	□□□□□□□	□□□□0□1	1□□□01	□□□□□□□	1□□1□□	□1□□□□
RBP	□□	□□□-□□dergro□□d Co□d□□t									
RBP	□0	Pri□ ar□HT	DDI□PHT	□□□□□□□	□□□□□□□	□□□□□□	1□□□□□0	□□□□0	1□□□□□□	□□0□□	□□□11
RBP	□1	Pri□ ar□	DDI□TP□□	1□□□1□□	□□□□0□	□□□□□□	□□□□□1	1□□□□	0	0	1□□1□
RBP	□□	□e□o□dar□	CDI□T□O□C	□□□□□□□	1□□□□0□	□□□□□□	□□□□□□	0	0	0	□□□□1
RBP	□□	Tota□□□o□□t □□□		1□0□□□□□	□□□□□□□	1□□□□□1	1□0□□□1	□□□□□	1□□□□□	□□0□□	1□□□□0
RBP	□□	□□□-□□dergro□□d Co□d□□tor□ □ De□i□e□									
RBP	□□	Pri□ ar□HT	DDI□PHT	1□□□□□□□	□□1□□□□	1□□□□□	□□□□□□0	10□00□	□□□□□0□	1□□□□□	□□□□□
RBP	□□	Pri□ ar□	DDI□TP□□	□□□□1□□	1□□□□□□	□□□1□□	□□□□□1	□□□□□	0	0	□□□□□
RBP	□□	□e□o□dar□	CDI□T□□□C	□□□□□□0	□□1□□□□	□□□□□1	□□□□□1	0	0	0	1□□□□□
RBP	□□	Tota□□□o□□t □□□		□□□□□□1□	1□1□□□□□	□0□□□1□	□1□□□0□	1□□□□1	□□□□□0□	1□□□□□	□□□□□□
RBP	□□	□□□-□i□e Tra□□for□er□	DDI□T□□T	□□0□□□□	□0□□□□□	1□□□111	□□□□□□	0	0	0	□□□□□
RBP	□0	□□□-□er□i□e□	C□ER□ICE	□0□□□□	□□0□□□1	□1□□□□	1□□□1□1	□□□□	□□□□□	0	0
RBP	□1	□□0-Meter□	CMETER□	□□□□1□0	□□□□□□0	□□□□□□	□□□□□□	1□□□1	1□□□0□	1□□	0
RBP	□□	□□1-I□□ta□atio□ o□ C□□to□er Pre□i□e□	C□□TPREM	1□□□□□□	10□□0□	1□□0□	1□□□□□	0	0	0	□□□□
RBP	□□	□□□-□treet □ighti□g □ □ig□a□□□te□ □	C□IGHT	□□□□□□□	0	0	0	0	0	0	□□□□□□
RBP	□□	□□□-□□□et Retire□e□t Co□t□for Di□trib□tio□ P□a□t	DI□TP□TX□R	□□□□□□	1□1□□□	□□1□	□□□0	1□	□□1□	1□	□0
RBP	□□	TOT□□ DI□TRIB□TIO□ P□□□T		10□□1□□□□□	□□□□□□□□□	1□□□□□□□□	□□1□□□□□□	□□□□□□	1□□□□□□□	□0□□□□	1□□□□1□
RBP	□□										
RBP	□□										
RBP	□□										
RBP	□□										
RBP	□0										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
RBP	□1	**ELECTRIC PLANT IN SERVICE CONTINUED**									
RBP	□□										
RBP	□□	GE□ER□□ P□□□T									
RBP	□□	□□□-□a□d a□d □a□d Right□	□□□□ □GE□	□□□	□□□	1□0	1□□	□	101	□	10
RBP	□□	□□0-□tr□□t□re□a□d l□ □ro□e□ e□t□	□□□□ □GE□	□□□□□0	□□□□1□	□□□□□	□□□□□	□□□	□□□□□	□1□	□□0
RBP	□□	□□1-Offi□e F□r□it□re □ E□□i□□ e□t	□□□□ □GE□	1□□□□□	11□1□□	□□□□□	□□□□□	10□	□0□□	□1	□0□
RBP	□□	□□□-□tore E□□i□□ e□t	□□□□ □GE□	□□	□□	□	□	0	□	0	0
RBP	□□	□□□-Too□□□ho□ □ Garage E□□i□□	□□□□ □GE□	□□□□□	□□□□0□	□□□□□	□□□□0	□□□	□□□□1	□□□	□□□
RBP	□□	□□□-□aborator□E□□i□□ e□t	□□□□ □GE□	1□□	□□	1□	□0	1	1□	1	1
RBP	□0	□□□-Co□ □ □□i□atio□ E□□i□□ e□t	□□□□ □GE□	1□□□□□	□□□□□	□1□1□	□□□□0	□1□	1□□□□	□□□	1□□□
RBP	□1	□□□-Mi□□e□a□eo□□ E□□i□□ e□t □□RO	□□□□ □GE□	□□□	□□0	□0	□□	□	□□	□	□
RBP	□□	□□□-Other Ta□gib□e Pro□ert□	□□□□ □GE□	1□□□	□□□	□1□	□□□	□	1□□	□	1□
RBP	□□	TOT□□ GE□ER□□ P□□□T		□□□0□□	1□□□1□1	□□□1□□	□□□11□	1□□□1	□0□□□	1□□□	□0□0
RBP	□□										
RBP	□□										
RBP	□□	**TOTAL ELECTRIC PLANT IN SERVICE**		11□□□□□0□	□□□□□□□□	1□□□□01□	□□□□1□□	□□□00	1□□0□□0□□	□□□□□	1□□□□□
RBP	□□										
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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)
RBD	1	**LESS: ACCUMULATED DEPRECIATION**									
RBD											
RBD		I□T□□GIB□E P□□□T □CC□M□□□TED DEPRECI□TIO□	I□TP□T	□□□□□□	□□□□□□	□□□□□	10□□□□	□□□	□□□□□	□□0	□0□
RBD											
RBD		TR□□□MI□□IO□ P□□□T □CC□M□□□TED DEPRECI□TIO□	TR□□P□T	0	0	0	0	0	0	0	0
RBD											
RBD		DI□TRIB□TIO□ P□□□T □CC□M□□□TED DEPRECI□TIO□									
RBD		□□0-□a□d □ □a□d Right□	P□T□□□0	□10	1□1	□0	□1	□	□1	□	□
RBD		□□1-□tr□□t□re□ □ I□ □ro□e□ e□t□	P□T□□□1	□□□□□□	□0□□□0	□□□□1	10□□□□	□□□	1□□□01	□□0	□□0
RBD	10	□□□-□tatio□ E□□i□□ e□t	P□T□□□□	□□□□□□1	□0□□□□	□□□01□	10□□□1□	□□□0□	1□□□□□	□□□1	□□□□
RBD	11	□□□-Po□e□To□er□ □ Fixt□re□	P□T□□□□	□□□0□□	□□□□□□	11□□□□	1□□□□□	□□□	□□□0□	□□□	1□0□□
RBD	1□	□□□-O□erhead Co□d□□tor□ □ De□i□e□	P□T□□□□	□1□□□0	1□□□□□	□□□□□	□□□□□	1□□□□	□□□□□	1□□□□	□□11□
RBD	1□	□□□-□□dergro□□d Co□d□it	P□T□□□□	1□□□1□□	100□1□1	□□□□□	□□□□□	1□1□□	□1□11	1□□□□	□□□□□
RBD	1□	□□□-□□dergro□□d Co□d□□tor□ □ De□i□e□	P□T□□□□	□0□□□□	10□□□□	□□□□□	□□□□0□	1□□□□	□□□□□	1□□□1	□□□□
RBD	1□	□□□-□i□e Tra□□for□er□	P□T□□□□	1□□□□0□	□□□□0	□□□□	□□□□1□	0	0	0	1□□□□
RBD	1□	□□□-□er□i□e□	P□T□□□□	□1□0□□	11□□□1□	1□□□□□	□□□□□	1□□	1□□□□	0	0
RBD	1□	□□0-Meter□	P□T□□□0	□□□□□□	1□□□□□	□□□□1	□□□□□	□□□	10□□1□	1□□	0
RBD	1□	□□1-I□□ta□atio□ o□ C□□to□er Pre□i□e□	P□T□□□1	11□□□□	□000	1□□□□	1□0□□	0	0	0	□□□
RBD	1□	□□□-□treet □ighti□g □ □ig□a□□□te□ □	P□T□□□□	□□□1□□	0	0	0	0	0	0	□□□1□□
RBD	□0	□□□-□□□et Retire□e□t Co□t□for Di□trib□tio□ P□a□t	DI□TP□TX□R	1□□0□	□□0	□□□	□□1	10	□□□	1□	□□
RBD	□1	TOT□□ DI□TRIB□TIO□ P□□□T □CC□M□□□TED DEPRECI□TIO□		□0□□□□□□	1□0□0□□□□	□□□□□1□	□□□□□□□	10□1□□	□□□□□□0	1□□1□□	□1□0□□
RBD	□□										
RBD	□□	GE□ER□□P□□□T □CC□M□□□TED DEPRECI□TIO□	GE□□P□T	1□□□1□1	□□□0□□	1□□□□1	1□□□□0	□1□	1□□0□0	□1□	1□□□□
RBD	□□										
RBD	□□	**TOTAL ACCUMULATED DEPRECIATION**		□□□□□□□□	1□1□□□□00	□□□□□□1	□□□□□□0	11□1□□	□□□□00□	1□□1□1	□□□□□1
RBD	□□										
RBD	□□										
RBD	□□										
RBD	□□	**NET ELECTRIC PLANT IN SERVICE**		□□□□□1□□	□□□□1□□□□	1□□10□□□1	1□□□□□1□	□□□□□□	1□□0□0□□	□□□101	1□□□□□
RBD	□0										
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PECO Energy Company
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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)
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**									
RBO											
RBO		**PLUS: ADDITIONS TO RATE BASE**									
RBO											
RBO		COMMO□ P□□□T	□□□□ □GE□	□□□□□□□	□□□□□0□	□1 □□0□	□□□□□□□	□□0□□	□0 □□□0	□□□□□□	□□□□□□
RBO											
RBO		**WORKING CAPITAL**									
RBO		P□r□ha□ed Po□er Ca□h □ or□i□g Ca□ita□	□CH RBC□□□□ □□	□□□1 □□	□□□0 □□	□□□□□□	□□□□□□	□□	□□1 □□	0	□□
RBO		Tra□□□ i□□io□ Ca□h □ or□i□g Ca□ita□	□CH RBC□□□□ □□	□□□1 □	□□11 □	□□□□	□□1 □0	□□	□□□□□□	□□	□
RBO	10	Di□trib□tio□									
RBO	11	Ca□h □ or□i□g Ca□ita□	□CH RBC□□□□ 1□	1 □□□□□□□	□□□□□□0	1 □□□□□□	□□□□□□1	□□1	□□□□□□□	□□0	1 □□0 □
RBO	1□	Materia□ a□d □□□□□ie□	TOTP□T	□0 □□□0	1 □□□□1	□□0 □□	□□0 □1	1 □□	□□0 □□	1 □□	□10
RBO	1□	Tota□Di□trib□tio□ □ or□i□g Ca□ita□		1 □0 □0 □□	□□□□□□0	1 □□□□□□	□0 □□1 □	□□□	□1 □□□□	□□□	□□□1 □
RBO	1□	TOT□□ □ OR□I□G C□PIT□□		□□□□1 □□	1 □□□□1 □	□□□□□□	□□□□□□	1 □11 □	□□□□□□	□1 □	□□□□□□
RBO	1□	TOT□□ □DDITIO□□ TO R□TE B□□E		□01 □1 □□	□□□□□□□	□□□1 □□	1 □□□□□□	□□1 □□	□□□10 □	□□□□□0	□□□□□□
RBO	1□										
RBO	1□	**LESS: DEDUCTIONS TO RATE BASE**									
RBO	1□	C□□to□ er De□o□it□	C□□TDEP	□□□□□1	1 □□□□□	□□□□1	□0 □□□□	1 □□	□□00 □	0	0
RBO	1□	C□□to□ er □d□a□□e□for Co□□tr□□tio□	C□□T□D□	□□□□□	1 □□□□	□□□0	□□□□	1 □	□□□□	□0	□□
RBO	□0	Deferred I□□o□ e Taxe□a□d Credit□									
RBO	□1	P□a□t	TOTP□T	□□□□□□□	□□□□□□□	1 □□□□□□	1 □0 □□□□	□□11 □	1 □□□□□□	□□□□□	1 □□1 □□
RBO	□□	Co□ □o□ P□a□t	□□□□ □GE□	□□□□□□	□□□□□□	□□□□1	11 □1 □□	□□0 □	□□□□□□	□□0	□□□
RBO	□□	Cor□orate □ter□ati□e Mi□i□ □□ Tax	TOTP□T	□1 □0 □□□□□	□□□□□□□□	□1 □□□1 □□	□□□□□□□□	□□□□□	□1 □□□□□□	□□□□□	□□□1 □0 □
RBO	□□	□□a□ orti□ed □MR I□□e□t□ e□t	CMETER□	0	0	0	0	0	0	0	0
RBO	□□	Co□trib□tio□□i□ □id of Co□□tr□□tio□ □CI□C□	C□□T□D□	□□□1 □□□	□1 □□□□□□	□□□□00 □	□□1 □1 □	□1 □□□	□□□□□□□	□1 □0 □	□□□□□
RBO	□□	Tota□Deferred I□□o□ e Taxe□a□d Credit□		□□□□□1 □	□□□□0 □□	11 □□□1 □	1 □0 □□□□	□□□□□	11 □□□1 □	□□□□□	1 □□□□□
RBO	□□	TOT□□ DED□CTIO□□ TO R□TE B□□E		□□□□□□□	□□□□□□□	1 □0 □0 □□	□0 □□□□1	□□□□□	1 □0 □□1 □	□□□□□	1 □□□1 □
RBO	□□										
RBO	□□										
RBO	□0	Tota□Di□trib□tio□ □dditio□□to Rate Ba□e		□□□□0 □□	□□□□1 □□	□0 □□□□	1 □□□□01	□□0 □0	□□□0 □□	□□□□□	□□1 □0
RBO	□1										
RBO	□□	TOT□□ P□RCH□□ED PO□ ER R□TE B□□E		□□□1 □□	□□□0 □□	□□□□□	□□□□□	□□	□□1 □□	0	□□
RBO	□□	TOT□□ TR□□□M□□IO□ R□TE B□□E		□□□1 □	□□11 □	□□□□	□□1 □0	□□	□□□□□□	□□	□
RBO	□□	TOT□□ DI□TRIB□TIO□ R□TE B□□E		□□□00 □□□□	□□□0 □□□□	1 □1 □1 □□□1	1 □□□□□□□	□□□□□0	1 □1 □□□□1	□□□□10	1 □□□1 □
RBO	□□										
RBO	□□	**TOTAL RATE BASE**		□□□□□□□	□□□□□□□	1 □1 □□□□□	1 □□0 □□□0	□□□0 □□	1 □1 □□□□□	□□□□□	1 □□□□□
RBO	□□										
RBO	□□										
RBO	□□										
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PECO Energy Company
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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	1	**CASH WORKING CAPITAL (LEAD LAG)**									
RBC		**DISTRIBUTION**									
RBC		O□M EXPE□□E RE□□TED C□□H □ OR□I□G C□PIT□□									
RBC		Pa□ro□□Di□trib□tio□ O□□□	□□□□ □GE□	1□□□□□□	10□□□□□	□□□□□□	□□□□□□	□□1	1□□□□□	□□□	1□□□□
RBC		Pe□□io□	□□□□ □GE□	□□□1□	1□□□□	□1□	□□□	1□	□□0	1□	□□
RBC		Other Ex□e□□e□	OMXPPPP	□□□□□□□	□□□□0□0	□□□□1□	10□□□□□	□0□□	□0□□0□	□1□1	□1□□
RBC		TOT□□ EXPE□□E□		□□□□□1□	□0□□□1□	11□0□□	1□□00□	□00□	□0□1□□	□□□□□	□0□□
RBC		POR □ or□i□g Ca□ita□	POR	1□□□□0□	□□□□□□0	□□□□□□	□□□□00	□□□□□	□□□□□□	0	□□□□□
RBC		TOT□□ EXPE□□E□ PER D□□		□□□□□	□□1□□	□1□	1□□□□	□1	1□1□□	11	□□
RBC	10										
RBC	11	C□ C RE□□IREME□T □TOT□□ EXPE□□E□ x EXPE□□E □□G□		□1□□1□	□□□1□□	□□□01	□□□□0□	□□1	□0□□□□	1□□	□□□
RBC	1□										
RBC	1□	□□ER□GE PREP□□ME□T□		□□□□□	□□1□□	1□1□□	1□□□1	□□	□□□	□□	□□
RBC	1□	DI□TRIB□TIO□ □CCR□ED T□XE□		□0□0□□	□□□□0□	□□□□□	1□□□□□	□□□	□□1□□	□□0	1□□0□
RBC	1□	I□TERE□T P□□ME□T□	TOTP□T	□□0□□□1□	□10□□□□□	□□□□0□□	□□□0□□□	□10□□	□□□□□□□	□1□□□	□□□□□
RBC	1□										
RBC	1□										
RBC	1□	□ET DI□TRIB□TIO□ C□□H □ OR□I□G C□PIT□□ RE□□IREME□T		1□□□□□□	□□□□□□0	1□□□□□	□□□□□1	□□1	□□□□□□	□□0	1□□0□
RBC	1□										
RBC	□0										
RBC	□1	**PURCHASED POWER**									
RBC	□□	O□M EXPE□□E RE□□TED C□□H □ OR□I□G C□PIT□□									
RBC	□□	Co□ □odit□P□r□ha□ed - Co□tra□t P□r□ha□e□	E□ERG□1	□□□□□□□	□□0□□00	1□□□1□□	1□□□□□□	1□00□	□□□□□□1	0	□□□
RBC	□□	Co□ □odit□P□r□ha□ed - □□ot Mar□et P□r□ha□e□	E□ERG□1	□□1□0	□□□□1	1□□□□□	1□1□1	□	□□□□	0	□
RBC	□□	TOT□□ EXPE□□E□		1□00□□□1□	□□□□□□1	1□□□□□□	1□□□□□0	1□01□	□□□□□1	0	□00
RBC	□□										
RBC	□□	TOT□□ EXPE□□E□ PER D□□		□□□□0	1□□□0	□□□	□□0	□	1□1	0	□
RBC	□□										
RBC	□□	PP C□ C RE□□IREME□T □TOT□□ EXPE□□E□ x EXPE□□E □□G□		□□□1□□	□□□0□□	□□□□□	□□□□□	□□	□□1□□	0	□□
RBC	□0										
RBC	□1	E□erg□ □CCR□ED T□XE□	E□ERG□1	0	0	0	0	0	0	0	0
RBC	□□										
RBC	□□	□ET E□erg□C□□H □ OR□I□G C□PIT□□ RE□□IREME□T		□□□1□□	□□□0□□	□□□□□	□□□□□	□□	□□1□□	0	□□
RBC	□□										
RBC	□□	**TRANSMISSION**									
RBC	□□	O□M EXPE□□E - PJM Tra□□□ i□□io□ P□r□ha□e	DTR□□	□1□□□□	□□□0□□	□□□□□1	□0□1□□	□□□□	□□□□0□	□1□	□□
RBC	□□										
RBC	□□	TOT□□ EXPE□□E□ PER D□□		□□1	10□	1□	□□	□	□□	□	0
RBC	□□										
RBC	□0	C□ C RE□□IREME□T □TOT□□ EXPE□□E□ x EXPE□□E □□G□		□□□1□	□□11□	□□□□	□□1□0	□□	□□□□□□	□□	□
RBC	□1										
RBC	□□	TR□□□MI□□IO□ □CCR□ED T□XE□	DTR□□	0	0	0	0	0	0	0	0
RBC	□□										
RBC	□□	□ET TR□□□MI□□IO□ C□□H □ OR□I□G C□PIT□□ RE□□IREME□T		□□□1□	□□11□	□□□□	□□1□0	□□	□□□□□□	□□	□
RBC	□□										
RBC	□□										
RBC	□□	□ET TOT□□ C□□H □ OR□I□G C□PIT□□ RE□□IREME□T		□1□□□□□	11□□□□□	□□□□□□	□□□□0□	□□□□	□□□□□0	□1□	1□□□□
RBC	□□										
RBC	□□										
RBC	□0										

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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	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**									
RBC											
RBC		**LAG/LEAD DAYS**		**NET DAYS**							
RBC		RE□E□□E □□G D□□□	□1□□□								
RBC		EXPE□□E □□G D□□□	□□□□□	1□□□□							
RBC		P□RCH□□ED PO□ ER RE□E□□E □□G D□□□	□1□□□								
RBC		P□RCH□□ED PO□ ER EXP □□G D□□□	□□□□□	1□□□□							
RBC		TR□□□MI□□IO□ RE□E□□E □□G D□□□	□1□□□								
RBC		TR□□□MI□□IO□ EXP □□G D□□□	1□□□0	□□□□□							
RBC	10	DI□TRIB□TIO□ RE□E□□E □□G D□□□	□1□□□								
RBC	11	DI□TRIB□TIO□ □□G D□□□	□□□□□	1□□1□							
RBC	1□										
RBC	1□										
RBC	1□										
RBC	1□										
RBC	1□	DI□TRIB□TIO□ □CCR□ED T□XE□									
RBC	1□	Federa□ □□o□e Tax	EBT	1□□11□1□□	1□□□□1□1	□□□□□0□	□□□□□□	□□□□	1□□□□□	□□□□0□	□□□□□
RBC	1□	□tate I□□o□e Tax	EBT	□□1□□□□	□0□□□1□	□□□□□□	□□□□□	□□□	□□□1□	□□□□	□□□□
RBC	1□	P□RT□ Taxe□	P□T□□□01	□□□□□0	□□0□1□□	□1□□□□	1□□□1□	□□□0□	1□□□□□	□□□□	□□□0□
RBC	□0	Ca□ita□□to□□	C□P□TOC□	0	0	0	0	0	0	0	0
RBC	□1	P□ □ □o□a□□e Taxe□	C□□IMRE□	0	0	0	0	0	0	0	0
RBC	□□	P□ Pro□ert□tax	TOTP□T	□□□□□□	1□□□0□□	□□□□□1	□□□0□	1□□□□	□□□□□	□□□0	□11□
RBC	□□	P□ Cor□ □oa□ Tax	TOTP□T	0	0	0	0	0	0	0	0
RBC	□□	Phi□ade□hia BPT	□□□E□RE□	0	0	0	0	0	0	0	0
RBC	□□	□o□a□Pri□ege Tax	□□□E□RE□	0	0	0	0	0	0	0	0
RBC	□□	Gro□□ Re□ei□t□ Tax	□□□E□RE□	□□□□□□□□1	1□□□□□□□1	□□□□□□□	□□□0□□□□	1□□□□□	□□□□□□□	11□□□□	□1□□□1
RBC	□□	□ag Da□□ eighted □□□r□ed Taxe□		□□□□1□□1□□	1□□□□□□□	□0□□□1□□	□□□□□0□0	1□□□□□	□□□□1□□□	1□□□□□	□□□□□
RBC	□□	Tota□□□r□ed Taxe□C□ C		□0□0□□	□□□□0□	□□□□□	1□□□□□	□□□	□□1□□	□□0	1□□0□
RBC	□□										
RBC	□0	DI□TRIB□TIO□ □□ER□GE PREP□□ME□T□									
RBC	□1	C□□to□er Ex□erie□□e	C□□T	1□□	1□□	□□	1□	0	0	0	1
RBC	□□	EEI□E□P a□d EPRI D□e□	C□□IMRE□	□□□	□□□	□□	□0	□	□1	□	□
RBC	□□	P□C □□□e□□- E□ē□tri□	C□□IMRE□	□□□□□	1□□□□	□□□	□□□	1□	□1□	1□	□□
RBC	□□	Pre□aid Re□t□a□d Po□ē □tta□h□e□t Fee□	P□T□□□□	□□□	□□1	□□	□□	□	□□	□	□
RBC	□□	□a□d □ea□i□g	DI□TP□T	□0	□□	□	1□	0	□	0	1
RBC	□□	E□□i□□ e□t Mai□te□a□□e	DI□TP□T	1□□	□0	1□	□□	1	1□	1	□
RBC	□□	B□□i□e□□ □□□□ort □□□te□	C□□T	□0□	□1□	□□	□□	0	1	0	□
RBC	□□	□EB□ □d□□□t□ e□t	□□□□ □GE□	□□□□1	1□□□□	□□0	□□□	1□	□□□	11	□□
RBC	□□	Fa□i□tie□Co□tra□t□	DI□TP□T	□□	1□	□	□	0	□	0	1
RBC	□0	IT □er□i□e Co□tra□t□	TOTP□T	□□□	□□1	□1	10□	□	□□	□	□
RBC	□1	F□et □□ti□tie□	GE□□P□T	□□1	1□1	□□	□□	□	□□	1	□
RBC	□□	Po□tage	C□□TBI□□□	□□□	□□□	□□	□□	0	1	0	□
RBC	□□	TOT□□ □□ER□GE PREP□□ME□T□		□□□□□	□□1□□	1□1□□	1□□□1	□□	□□□	□□	□□
RBC	□□										
RBC	□□										
RBC	□□										
RBC	□□										
RBC	□□										
RBC	□□										
RBC	□0										

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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	1	**OPERATING REVENUES**									
RBC	2										
RBC	3	**SALES REVENUES**									
RBC	4	Base of Electric Rate - Base		1,[illegible]1,[illegible]	[illegible]1,[illegible]	1,[illegible]1	[illegible]01[illegible]	[illegible]	1,[illegible]	[illegible]0[illegible]	[illegible]0[illegible]
RBC	5	Base of Electric Rate - [illegible]ear Deo[illegible] i[illegible]io[illegible]g E[illegible]ERG[illegible]		[illegible]1[illegible]	[illegible]1[illegible]	[illegible]	[illegible]	[illegible]	[illegible]1[illegible]	[illegible]1[illegible]	[illegible]0[illegible]
RBC	6	Tra[illegible] i[illegible]io[illegible] Re[illegible]e[illegible]	DTR[illegible]R	1[illegible]1	11[illegible]1[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
RBC	7	P[illegible]r[illegible]ha[illegible]ed E[illegible]tri[illegible] Re[illegible]e[illegible]	E[illegible]ERG[illegible]1	1[illegible]0[illegible]1[illegible]00	[illegible]0[illegible]	1[illegible]0[illegible]	1[illegible]	1[illegible]0[illegible]	[illegible]0[illegible]0	0	[illegible]
RBC	8	TOT[illegible] [illegible]E[illegible] OF E[illegible]ECTRICIT[illegible]		[illegible]	1[illegible]	[illegible]0[illegible]0	[illegible]11	[illegible]	[illegible]0[illegible]1[illegible]	[illegible]	[illegible]
RBC	9										
RBC	10	**OTHER OPERATING REVENUES**									
RBC	11	[illegible]bi[illegible]ed a[illegible]d Co[illegible]t [illegible]d[illegible]t[illegible] e[illegible]t Re[illegible]e[illegible]e	[illegible]E[illegible]RE[illegible]	0	0	0	0	0	0	0	0
RBC	12	[illegible]0-Forfeited Di[illegible]o[illegible]t[illegible]	OX[illegible]0[illegible]	1[illegible]	[illegible]11[illegible]	[illegible]0[illegible]	[illegible]	[illegible]	1[illegible]	0	1
RBC	13	[illegible]-Re[illegible]t fro[illegible] E[illegible]e[illegible]tri[illegible] Pro[illegible]ert[illegible]	TOTP[illegible]T	[illegible]0	11[illegible]0	[illegible]000	[illegible]	1[illegible]0	[illegible]0[illegible]	1[illegible]	[illegible]0
RBC	14	[illegible]-Other E[illegible]e[illegible]tri[illegible] Re[illegible]e[illegible]e[illegible]									
RBC	15	Co[illegible]e[illegible]tio[illegible] Charge[illegible] Ret[illegible]r[illegible]ed Che[illegible]Fee[illegible]	C[illegible]T	[illegible]	[illegible]	[illegible]	[illegible]	1	[illegible]	0	[illegible]
RBC	16	[illegible]Other	DI[illegible]TP[illegible]T	1[illegible]	[illegible]	1[illegible]	[illegible]	[illegible]	1[illegible]1	[illegible]0	[illegible]
RBC	17	Tota[illegible]-Other E[illegible]e[illegible]tri[illegible] Re[illegible]e[illegible]e[illegible]		1[illegible]1	[illegible]	[illegible]	[illegible]0[illegible]	[illegible]	1[illegible]	[illegible]0	[illegible]1
RBC	18	TOT[illegible] OTHER OPER[illegible]TI[illegible]G RE[illegible]		[illegible]	[illegible]0[illegible]	[illegible]1[illegible]	[illegible]0[illegible]	1[illegible]	[illegible]00[illegible]	[illegible]	[illegible]
RBC	19										
RBC	20	**TOTAL OPERATING REVENUES**		[illegible]0[illegible]1[illegible]	1[illegible]0[illegible]	[illegible]	[illegible]0	[illegible]	[illegible]01	[illegible]1[illegible]	[illegible]
RBC	21										
RBC	22										
RBC	23										
RBC	24										
RBC	25										
RBC	26										
RBC	27										
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RBC	90										
RBC	91										
RBC	92										
RBC	93										
RBC	94										
RBC	95										
RBC	96										
RBC	97										
RBC	98										
RBC	99										
RBC	100										

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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	1	**OPERATION & MAINTENANCE EXPENSE**									
E											
E		PROD□CTIO□ EXPE□□E									
E		Other Po□er □□□□□									
E		□□□- P□r□ha□ed Po□er - Ca□a□it□	E□ERG□1								
E		Tota□Other Po□er □□□□□									
E		TOT□□ PROD□CTIO□ EXPE□□E									
E											
E		TR□□□MI□□IO□ EXPE□□E□									
E	10	O□eratio□ Ex□e□□e	DTR□□R								
E	11	Mai□te□a□□e Ex□e□□e	DTR□□	0	0	0	0	0	0	0	0
E		TOT□□ TR□□□MI□□IO□ EXPE□□E									
E											
E		DI□TRIB□TIO□ EXPE□□E□									
E		O□eratio□									
E		□□0-□□□er□i□io□	□□□□ □GDO								
E		□□1-□oad Di□□at□h	DI□TP□T	0	0	0	0	0	0	0	0
E		□□□-□tatio□ E□□i□□ e□t	P□T□□□□								
E		□□□-O□erhead □i□e□	OHDI□T								
E		□□□-□□dergro□□d □i□e□	□GDI□T								
E		□□□-□treet □ighti□g	P□T□□□	0	0	0	0	0	0	0	0
E		□□□-Meteri□g	CMETER□								
E		□□□-C□□to□er I□□ta□atio□□	C□□T								
E		□□□-Mi□□e□a□eo□□	DI□TP□T								
E		□□□-Re□t□	DI□TP□T								
E		Tota□Di□trib□tio□ O□eratio□									
E											
E		Mai□te□a□□e									
E		□□0-□□□er□i□io□	□□□□ □GDM	0	0	0	0	0	0	0	0
E		□□1-□tr□□t□re□	P□T□□□								
E		□□□-□tatio□ E□□i□□ e□t	P□T□□□□								
E		□□□-O□erhead □i□e□	OHDI□T								
E		□□□-□□dergro□□d □i□e□	□GDI□T								
E		□□□-Tra□□for□er□	P□T□□□□					0	0	0	
E		□□□-□treet □ighti□g	P□T□□□□		0	0	0	0	0	0	
E		□□□-Meteri□g	CMETER□	0	0	0	0	0	0	0	0
E		□□□-Mi□□e□a□eo□□	DI□TP□T								
E		Tota□Di□trib□tio□ Mai□te□a□□e									
E											
E		TOT□□ DI□TRIB□TIO□ P□□□T O□M EXPE□□E□									
E		TOT□□ P□RCH□□ED PO□ ER O□M EXPE□□E□									
E		TOT□□ TR□□□MI□□IO□ O□M EXPE□□E□									
E											
E		TOT□□ OPER □ M□I□T EXP □PROD□TR□□ □□ DI□T□									
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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	1	**OPERATION & MAINTENANCE EXPENSE CONTINUED**									
E											
E		CUSTOMER ACCOUNT EXPENSE									
E		901-Supervision	CUST	0	0	0	0	0	0	0	0
E		902-Meter Reading	CMETER			10	1			1	0
E		903-Customer Records and Collection Expense	CUSTREC	10	0	1					
E		904-Uncollectible Accounts	EXP				1			0	
E		905-Miscellaneous Customer	CUSTM			1		11	0		
E		TOTAL CUSTOMER ACCOUNT EXPENSE		1	0	1	1				0
E	0										
E	1										
E		CUSTOMER SERVICE EXPENSE									
E		907-Supervision	CUST	0	0	0	0	0	0	0	0
E		908-Customer Assistance	CUSTM	1	1	0				0	
E		909-Information and Instructional Expense	CUSTM	1	0	1	0	0		0	11
E		910-Miscellaneous Customer	CUSTM	1	0	11		0		0	
E		TOTAL CUSTOMER SERVICE EXPENSE		1	1	0				0	
E											
E		SALES EXPENSE	CUSTM	0	0	1	0		0	0	0
E	0										
E	1	TOTAL OPERATION EXCLUDING A&G		1	1	1	0	0	1	0	1
E											
E		ADMINISTRATIVE AND GENERAL EXPENSE									
E		920-Administrative and General	AGE	0	1	0	0	1	0	1	0
E		921-Office Supplies	AGE		0	101		0		1	
E		922-Office Supplies Expense	AGE		1	1	0	1			
E		923-Property Insurance	DGPT		1			1			1
E		924-Injuries and Damages	AGE	1		1	1		1		1
E		925-Employee Pensions and Benefits	AGE	1	1	01		1	0	1	0
E	0	926-Regulatory Commission	IMRE	10	1	0	1	1	0	1	
E	1	927-Duplicate Charges-Credit	IMRE	1	0	0	1	1	10		10
E		928-Miscellaneous General									
E		RRH	RRH	0	0	0	0	0	0	0	0
E		G	RG	0	0	0	0	0	0	0	0
E		GPDHT	CTCI	0	0	0	1	0	1	0	0
E		Transmit Charging - G	CTCRE	1	0	0	1	0	0	0	0
E		Transmit Charging - PDHT	CTCRECI	1	0	0	0	0	0	0	0
E		Other	IMRE	1	1	0	1	10	0	10	0
E		Total 928-Miscellaneous General	PT	1	1	0	1	0	1	10	0
E	0	929-Maintenance of General Plant	GE	1	1	1	0	1	0	0	0
E	1	TOTAL A&G EXPENSE		1	10	1	1	0	1	0	1
E											
E		**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES**		1	1	10	1	1	1	10	1
E											
E		**TOTAL OPERATION & MAINTENANCE EXPENSES**		00	1	0	0	0	0	0	11
E											
E											
E											
E											
E	100										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**									
D											
D		I□T□□GIB□E P□□□T EXPE□□E	I□TP□T	□□□□□□	□□□□0□	□□□□□	10□□10	□□□	□□□1□	□□□	□□□
D											
D		TR□□□MI□□IO□ P□□□T EXPE□□E	TR□□P□T	0	0	0	0	0	0	0	0
D											
D		DI□TRIB□TIO□ P□□□T EXPE□□E									
D		□□0-□a□d □ □a□d Right□	P□T□□□0	0	0	0	0	0	0	0	0
D		□□1-□tr□□t□re□ □ I□ □ro□e□ e□t□	P□T□□□1	□□□□□	□□11□	□□□□	1□0□□	□0	1□□1□	□0	□□
D	10	□□□-□tatio□ E□□i□□ e□t	P□T□□□□	□□□□1□	10□□0□	□□□□□	□□1□□	1□□	□□□□□	□□□	1□□
D	11	□□□-Po□e□To□er□ □ Fixt□re□	P□T□□□□	□□□□□□	1□□□□□	□□□□□	□□□□□	□0□	□□□01	□0□	□□□
D	1□	□□□-O□erhead Co□d□□tor□ □ De□i□e□	P□T□□□□	□□□□□□	□□□□□	□□□0□	□□□□□	□1□	□□□□□	□1□	□□1
D	1□	□□□-□□dergro□□d Co□d□it	P□T□□□□	1□□0□1	□□0□1	□□□□□	□□□□□	10□	□□□□□	1□□	□1□
D	1□	□□□-□□dergro□□d Co□d□□tor□ □ De□i□e□	P□T□□□□	□0□□□□	□□□□00	□□□1□	□□□□□	□0□	□□□1□	□□0	□0□
D	1□	□□□-□i□e Tra□□for□er□	P□T□□□□	□1□□□□	11□□□□	□□□□□	□□00□	0	0	0	1□□
D	1□	□□□-□er□i□e□	P□T□□□□	□□□□□	□□00□	□□□□	□□□□□	□	□1	0	0
D	1□	□□0-Meter□	P□T□□□0	1□□□10	1□□□□□	□□1□□	□□□□□	□□	□0□	11	0
D	1□	□□1-I□□ta□atio□ o□ C□□to□er Pre□i□e□	P□T□□□1	□	□	1	0	0	0	0	0
D	1□	□□□-□treet □ighti□g □ □ig□a□□□te□ □	P□T□□□□	□0□□	0	0	0	0	0	0	□0□□
D	□0	□□□-□□□et Retire□ e□t Co□t□for Di□trib□tio□ P□a□t	DI□TP□TX□R	0	0	0	0	0	0	0	0
D	□1	TOT□□ DI□TRIB□TIO□ P□□□T EXPE□□E		□□1□0□□	1□□□1□□	□1□□□0	□□□□□□	1□□□□	□0□□□□	1□□□□	□□□□□
D	□□										
D	□□	GE□ER□□P□□□T EXPE□□E	GE□□P□T	1□□□□□	11□□□□	□□□□1	□□□□□	10□	□□10□	□□	□0□
D	□□										
D	□□	COMMO□ P□□□T DEPRECI□TIO□ □□D □MORTI□□TIO□	□□□□ □GE□	□□□□□0	1□□□□1	□0□□	□□□0□	1□1	□□□□□	11□	□□□
D	□□										
D	□□	IIJ□ REG □□□ET □MORTI□□TIO□	TOTP□T	□□□□□	□□□□□	□□□□	□□□□	□□	□□0□	□□	□□
D	□□										
D	□□										
D	□0	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**		□□□□□□	1□□□0□□	□□□□□	□□□1□□	1□□□□	□1□□□□	1□□□□	□□□□□
D	□1										
D	□□										
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D	□□										
D	□0										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
TO	1	**OTHER OPERATING EXPENSES**									
TO											
TO		**TAXES OTHER THAN INCOME TAXES**									
TO		**General Taxes**									
TO		P□RT□ Taxe□	P□T□□□01	□□□□0	□□□1□	□□□	1□11□	□□	1□□□□	□□	□0
TO		Ca□ita□□to□□	C□P□TOC□	0	0	0	0	0	0	0	0
TO		Pa□ro□Re□ated	□□□□ □GE□	1□0□1	□□□□□	1□□□□	1□□□□	□□	1□□1□	□□	1□0
TO		P□ □ □o□a□□e Tax	C□□IMRE□	□00□	1□1□□	□□1	□□□	□	1□□	□	1□
TO		P□ Pro□ert□Tax	TOTP□T	□□□□0	□□□□□	□□□	□□□	□□	□□□	□□	□□
TO	10	P□ Cor□orate □oa□Tax	TOTP□T	0	0	0	0	0	0	0	0
TO	11	Tota□Ge□era□Taxe□		□□□□□□	1□□□□0	□□□□□	□□□□1	1□□	□□□□□	1□□	□□1
TO	1□										
TO	1□										
TO	1□	**Gross Receipt Tax**									
TO	1□										
TO	1□	P□r□ha□ed Po□er									
TO	1□	Retai□Re□e□□e	□CH RBC□□□ □□	1□0□1□□00	□□□□□0□	1□0□□□	1□□□□□	1□0□□	□0□□□0	0	□□□
TO	1□	Forfeited Di□□o□□t□		0							
TO	1□	□e□□□Bad Debt		0							
TO	□0	Tota□P□r□ha□ed Po□er Re□e□□e	C□□C□□□TED	1□0□1□□00	□□□□□0□	1□0□□□	1□□□□□	1□0□□	□0□□□0	0	□□□
TO	□1	Tota□P□r□ha□ed Po□er □ GRT Rate □□□0□	C□□C□□□TED	□□□□01	□0□□□□	10□□□□	□□□□1	□□	□00□	0	□0
TO	□□										
TO	□□	Tra□□□ i□□io□									
TO	□□	Retai□Re□e□□e	□CH RBC□□□ □□	1□□□□□1	11□□□1□	□□□□□□	□□□□□□	□□□	□□□□□□	□□□	□□
TO	□□	Forfeited Di□□o□□t□		0							
TO	□□	□e□□□Bad Debt		0							
TO	□□	Tota□Tra□□□ i□□io□Re□e□□e	C□□C□□□TED	1□□□□□1	11□□□1□	□□□□□□	□□□□□□	□□□	□□□□□□	□□□	□□
TO	□□	Tota□Tra□□□ i□□io□ □ GRT Rate □□□0□	C□□C□□□TED	11□□□□	□□□□□□	1□□□□	1□□□1	□□	1□□□□	□□	□
TO	□□										
TO	□0	Di□trib□tio□									
TO	□1	Retai□Re□e□□e		1□□□□□1□□	□□□□1□□	1□□□□□1	□□□□01□	□□□□□	1□□□□□□	□□0□□	□□□0□□
TO	□□	Forfeited Di□□o□□t□	□CH RBC□□□ □□	1□□□□□	□□11□	□□0□□	□□□□	□	1□□	0	1
TO	□□	□e□□□Bad Debt	□CH E□□□ □□	□□□□□□	□□□□□□	□□□□□	□□□□□	1□	□□□	0	□
TO	□□	Tota□Di□trib□tio□Re□e□□e	C□□C□□□TED	1□□□□□□□□	□00□□1□	1□□□0□□	□□□□□0□	□□□□□	1□□□□1□	□□0□□	□□□0□1
TO	□□	Tota□Di□trib□tio□ □ GRT Rate □□□0□	C□□C□□□TED	□1□□□□	□□□1□□	10□1□□	1□□□□□	□□0	10□□□□	□□1□	1□□□□
TO	□□										
TO	□□	Tota□Gro□□Re□ei□t□Tax		1□□□□□□	100□□□	□□□□□□	□□□□□□	□□□	1□□□□□	□□□	1□□□
TO	□□										
TO	□□	TOT□□P□RCH□□ED PO□ ER TOIT EXPE□□E□		□□□□01	□0□□□□	10□□□□	□□□□1	□□	□00□	0	□0
TO	□0	TOT□□TR□□□MI□□IO□ TOIT EXPE□□E□		11□□□□	□□□□□□	1□□□□	1□□□1	□□	1□□□□	□□	□
TO	□1	TOT□□DI□TRIB□TIO□ TOIT EXPE□□E□		11□□□□	□□□□□□	1□□□□	1□□□□	□□□	1□□□□	□□□	1□□□
TO	□□										
TO	□□	**TOTAL TAXES OTHER THAN INCOME**		1□□□□□□	11□□01□	□□□□0□	□0□□□□	□□□	1□□□□□	□□□	1□□0□
TO	□□										
TO	□□										
TO	□□										
TO	□□										
TO	□□										
TO	□□										
TO	□0										

PECO Energy Company
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For Future Test Year Ended December 31, 2025

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)
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**									
TI											
TI		TOT DI TRIB TIO OPER TI G RE E E		1 1 1	1 1	1 1		1	1 1		
TI		E									
TI		OPER TIO M I T I E CE EXPE E	CH E	1		10	1	1	1		10
TI		DEPRECI TIO D MORTI TIO EXPE E	CH D		1 0		1	1	1	1	
TI		T XE OTHER TH I COME T XE	CH TO 1	11		1	1		1		1
TI		ET OPER TI G I COME BEFORE T XE		0 1		1		1	1		0
TI		E									
TI	10	I TERE T EXPE E Rate Ba e 1 eighted Co t of Debt		1 1			1	1 0 1	1	1 10	
TI	11										
TI	1	**BASE TAXABLE DISTRIBUTION INCOME**		1 1 1	1 1			0	1 1	1	0 0
TI	1										
TI	1										
TI	1	**CALCULATION OF PA STATE INCOME TAXES**									
TI	1	B E T X B E I COME	CH TI 1	1 1 1	1 1			0	1 1	1	0 0
TI	1	E									
TI	1	tate Tax De re latio O er der Boo	TOTP T	0 1	1	0	1	1	1	01	1
TI	1	Other d t t e t	TOTP T	11		1			1 0		1 1
TI	0	Re air o a e Ded tio	TOTP T	10 100	10	1	1	1 11	1	1	
TI	1	P T TE T X B E DI TRIB TIO I COME		1 1	0 1	0		1	0	1	1
TI		O ti ation	TOTP T	0		0	1				1 1
TI		**PA STATE INCOME TAXES @ Tax Rate 7.99%**			0		1		1 1	1	1
TI		**PLUS:**									
TI		**DEFERRED STATE INCOME TAXES**									
TI		tate Deferred Taxe	TOTP T	1		1 1			1 0		1
TI		**DEFERRED STATE INCOME TAXES @ Tax Rate 7.99%**		1 01	1	1	0		1		1
TI		**TOTAL DISTRIBUTION STATE INCOME TAX EXPENSE**			1		1		1 0	1	
TI											
TI	0	**CALCULATION OF FEDERAL INCOME TAXES**									
TI	1	B E T X B E I COME	CH TI 1	1 1 1	1 1			0	1 1	1	0 0
TI		E									
TI		P tate I o e Taxe			0		1		1 1	1	1
TI		Federa Tax De re latio O er der Boo	TOTP T	0 1	10		1	111	0	1	
TI		Other d t t e t	TOTP T	10		1 0	1 00		1 1		1
TI		Re air o a e Ded tio	TOTP T	10 100	10	1	1	1 11	1	1	
TI		FEDER T X BE DI TRIB TIO I COME			1	1	1		1	1	
TI		**FEDERAL INCOME TAXES @ Tax Rate 21.00%**		1	1	1			1	0	1
TI		**PLUS:**									
TI	0	**DEFERRED FEDERAL INCOME TAXES**									
TI	1	Federa Deferred Taxe	TOTP T	1 1 0	1	1 1	1 0		1		0
TI		**DEFERRED FEDERAL INCOME TAXES @ Tax Rate 21.00%**			1 1		0	1	0	1	
TI		**LESS:**									
TI		**OTHER TAX ADJUSTMENTS**									
TI		E e tri P a t	TOTP T	0	0	0	0	0	0	0	0
TI		Co o P a t	GE	0	0	0	0	0	0	0	0
TI		ortiatio of I e t e t Tax Credit	EBT	1	11	0		0	1	0	0
TI		**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**		11 0	0		1 1	1	101		1
TI		**TOTAL DISTRIBUTION INCOME TAX EXPENSE**		1 1 1		10	0		0		1
TI	0										

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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)
TI	□1	**DEVELOPMENT OF INCOME TAXES CONTINUED**									
TI	□□										
TI	□□	**DEVELOPMENT OF PURCHASED POWER TAXES**									
TI	□□	P□RCH□□ED PO□ ER OPER□TI□G RE□E□□E□	□CH RBC□□□ □□	1□0□1 □□00	□□□□0□	1□0□□□□	1□□□□□□	1□0□□	□0□□□0	0	□□□
TI	□□	□E□□□									
TI	□□	OPER□TIO□ □ M□I□T□I□E□CE EXPE□□E	□CH E□□□ □1	1□00 □□□1□	□□□□□□1	1□□□□□□	1□□□□□0	1□01□	□□□□□1	0	□00
TI	□□	T□XE□ OTHER TH□□ I□COME T□XE□	□CH TO□□□ □□	□□□□01	□0□□□□	10□□□□	□□□□1	□□	□00□	0	□0
TI	□□	□ET OPER□TI□G I□COME BEFORE T□XE□		□□□□□	□□□□□	□□□	□□□	□	□0□	0	□
TI	□□	□E□□□									
TI	□0	I□TERE□T EXPE□□E □Rate Ba□e □□□1□□ □ eighted Co□t of Debt□		□□□	□1□	1□□	1□□	1	□□	0	1
TI	□1	**BASE TAXABLE PURCHASED POWER INCOME**		□□□□□	□□1 □□	□□□	□□□	□	1□□	0	□
TI	□□	□E□□□									
TI	□□	**PA STATE PURCHASED PWR INCOME TAXES @ Tax Rate 7.99%**		□□□	1□1	□□	□□	0	1□	0	0
TI	□□	E□ □ □ □ □ □									
TI	□□	**FEDERAL PURCHASED PWR INCOME TAXES @ Tax Rate 21.00%**		□□□	□1□	10□	□□	1	□1	0	1
TI	□□	□dditio□a□P□r□ha□e Po□er Ex□e□□e □O□		0	0	0	0	0	0	0	0
TI	□□										
TI	□□	**DEVELOPMENT OF TRANSMISSION TAXES**									
TI	□□	TR□□□MI□□IO□ OPER□TI□G RE□E□□E□	□CH RBC□□□ □□	1□□□□□1	11□□□1□	□□□□□□	□□□□□□	□□□	□□□□□□	□□□	□□
TI	□0	□E□□□									
TI	□1	OPER□TIO□ □ M□I□T□I□E□CE EXPE□□E	□CH E□□□ □□	1□□□□0□	10□□□□□	□□□□□□	□1□□1□	□□1□	□1□11□	□□□	□□
TI	□□	T□XE□ OTHER TH□□ I□COME T□XE□	□CH TO□□□ □0	11□□□□	□□□□□	1□□□□	1□□□1	□□	1□□□□	□□	□
TI	□□	□ET OPER□TI□G I□COME BEFORE T□XE□		1□0□□	□1□	1□1	1□□	□	1□□	□	0
TI	□□	□E□□□									
TI	□□	I□TERE□T EXPE□□E □Rate Ba□e □□□1□□ □ eighted Co□t of Debt□		□11	□□	1□	□□	□	□1	□	0
TI	□□	**BASE TAXABLE TRANSMISSION INCOME**		□□□	□□0	1□□	1□□	1	□□	□	0
TI	□□	□E□□□									
TI	□□	**PA STATE TRANSMISSION INCOME TAXES @ Tax Rate 7.99%**		□1	□□	1□	11	0	□	0	0
TI	□□	E□ □ □ □ □ □									
TI	□0	**FEDERAL TRANSMISSION INCOME TAXES @ Tax Rate 21.00%**		1□1	10□	□□	□□	0	1□	1	0
TI	□1										
TI	□□	**TOTAL PA INCOME TAX EXPENSE**		□□01□□	□□□	□□□□□□	□□1 □□□	□□□	□1 □□□□	□1 □□□	□□
TI	□□	**TOTAL FEDERAL INCOME TAX EXPENSE**		□11□1 □□□	□□□□□	□□□1 □□□	□□□0 □□□	□1 □1□	□□□0 □□□	□□□□□	1□□
TI	□□	**TOTAL INCOME TAX EXPENSE**		□1 □□1 □□□	□□□1□	□10 □□□□□	□□□□□□	□□□□□	□□□□□□	□□□□□	□□1
TI	□□										
TI	□□										
TI	□□										
TI	□□										
TI	□□	**TAX RATES**									
TI	□0	GRO□□ RECEIPT□ T□X R□TE	□□□0□								
TI	□1	□T□TE T□X R□TE	□□□□□								
TI	□□	□□CO□□ECTIB□E EXPE□□E□	0□00 □□1								
TI	□□	FEDER□□ T□X R□TE - C□RRE□T	□1□00□								
TI	□□	P□C □OC□ □ □B□ □□□E□□ME□T R□TE	0□00□□								
TI	□□	EFFECTI□E T□X R□TE	□□□□1 □1□								
TI	□□	□PC R□TE	0□00 □0□□								
TI	□□	GRO□□ RE□E□□E CO□□ER□IO□ F□CTOR	1□□□□□□□								
TI	□□	**WEIGHTED COST OF DEBT**	□□1 □00□								
TI	□□										
TI	100										

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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)
	1	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR**									
		PRODUCTION OTHER SALARIES & WAGES EXPENSE									
		P-Purchased Power	OX-PROD	0	0	0	0	0	0	0	0
		TOTAL PRODUCTION OTHER SALARIES & WAGES EXP		0	0	0	0	0	0	0	0
		TRANSMISSION SALARIES & WAGES EXPENSE									
		Operation	OX-TR	0	0	0	0	0	0	0	0
		Maintenance	MX-TR	0	0	0	0	0	0	0	0
	10	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0
	11										
		DISTRIBUTION SALARIES & WAGES EXPENSE									
		Operation									
		Supervision	OX								
		Overhead	OX								
		Underground	OX								
		Meter	OX								
		Customer Installation	OX								
		Miscellaneous	OX								
		Total Operation									
		Maintenance									
		Structure	MX								
		Station Equipment	MX								
		Overhead	MX								
		Underground	MX								
		Transformer	MX								
		Street Lighting	MX								
		Miscellaneous	MX								
		Total Maintenance									
		TOTAL DISTRIBUTION									
		CUSTOMER ACCOUNTS SAL & WAGES EXP									
		Record and Collection Expense	C-TREC								
		Miscellaneous	C-TC-M								
		TOTAL CUSTOMER ACCOUNTS SAL & WAGES EXP									
		CUSTOMER SERVICE SAL & WAGES EXP									
		Customer Installation	C-T								
		Demonstrating & Selling	C-T-D-T	0	0	0	0	0	0	0	0
		Miscellaneous	C-TC-M								
		TOTAL CUSTOMER SERVICE EXP									
		SALES EXPENSE (ACCT 912&916)	OX-C								
		ADMINISTRATIVE & GENERAL SALARIES & WAGES EX	GX-G								
		TOT OPER & MAINTENANCE LABOR									

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
F	1	**ALLOCATION FACTOR TABLE**									
F		**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
F											
F		**DEMAND**									
F		DEMAND - PRODUCTION RELATED									
F		Demand Production	DPROD	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
F											
F											
F											
F	10										
F	11	DEMAND - TRANSMISSION RELATED									
F	1	Demand Transmission 1 Coincident Peak	DTR	1	1	1	1	1	1	0	1
F	1										
F	1	Demand Transmission Revenue	DTRR	1	11	1					
F	1										
F	1										
F	1										
F	1										
F	1										
F	0	DEMAND - DISTRIBUTION RELATED Non-Coincident Peak Demand									
F	1	Demand Distribution Primary High Tension	DDIPHT	0	01	1 0	1 1		1	11 0	1
F		Demand Distribution Primary Overhead Line	DDITPO	1	01	1 0	1 1		0	0	1
F		Demand Distribution Primary Underground Line	DDITP	1	01	1 0	1 1		0	0	1
F											
F		Demand Distribution Secondary Overhead Line	DDITSO	0 0	01	1 0	1 1	0	0	0	1
F		Demand Distribution Secondary Underground Line	DDITS	0 0	01	1 0	1 1	0	0	0	1
F		Demand Distribution Overhead Line Transformer	DDITOT	0 0	01	1 0	1 1	0	0	0	1
F		Demand Distribution Underground Line Transformer	DDITST	0 0	01	1 0	1 1	0	0	0	1
F											
F	0										
F	1										
F											
F											
F											
F											
F											
F											
F											
F											
F	0										
F	1										
F											
F											
F											
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F											
F											
F											
F											
F											
F	0										

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
F	1	**ALLOCATION FACTOR TABLE CONTINUED**									
F		**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
F											
F		**ENERGY**									
F		E erg Re e at ro-for a ad ted e e	E ERG 1	1 0 1 00	0	1 0	1	1 0	0 0	0	
F		E erg Meter M h a e	E ERG	0	11 0 1	0		0 10	1	0	1 0
F											
F											
F											
F	0										
F	1										
F											
F											
F											
F		**CUSTOMER**									
F		- C t Di t e o dar OH i e CP	CDI T O	0 0	01 0	1 0 0	1 1	0	0	0	1
F		- C t Di t e o dar G i e CP	CDI T	0 0	01 0	1 0 0	1 1	0	0	0	1
F		- C t Di t e o dar Po e To er Fixt re	CDI T O C	1 1 1 1	1	0	1	0	0	0	
F		- C t Di t e o dar Co d tor De i e	CDI T C	1 1 1 1	1	0	1	0	0	0	
F	0										
F	1	-er i e	C ER ICE		0		1		1	0	0
F		0-Meter	CMETER		0		0	1	1	1	0
F		1-I ta atio o C to er Pre i e	C TPREM	1 1 1 1	1	0	1	0	0	0	
F		-treet ighti g ig a te	C IGHT	1	0	0	0	0	0	0	1
F											
F		C to er De o it	C TDEP	1 0000	0 0 0	0 0	0 1	0 00	0 0	0 0000	0 0000
F											
F											
F		0-C to er Re ord a d Co e tio	C TREC	1 0000	0	0 11	0 0	0 00	0 0	0 000	0 00
F	0	0-Mi e a eo C to er o t	C TC M	1 1 1	1	0	1				1
F	1	0-C to er i ta e	C T T	1 0000	0	0 1	0 0	0 0001	0 00	0 0000	0 00 0
F		0-I for atio a a d I tr tio a d erti g	C T D T	1 1 1	1	0	1				1
F		10-Mi e a eo C to er er i e	C TC M	1 1 1	1	0	1				1
F		1 1-Mi e a eo a e Ex e e	C T E	1	0 0000	0 0000	0 1	0 01	0 1	0 0000	0 0000
F											
F		ber of Bi	C TBI	0	1 0	0 0	1	0	1		1 0
F		ber of C to er	C T	1 1 1	1	0	1				1
F		ber of Re ide tia C to er	C TRE	1 110	1	0	0	0	0	0	0
F		ber of Co er ia a d I d tria C to er	C TCI	1	0	0	1			0	0
F	0										
F	1	Tra it Chargi g - G	CTCRE R	1	0	0	1	0	0	0	0
F		Tra it Chargi g - PD HT	CTCRE CI	1	0	0	0		0	0	0
F											
F											
F											
F											
F											
F											
F											
F	100										

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
□F	101	**ALLOCATION FACTOR TABLE CONTINUED**									
□F	10□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
□F	10□										
□F	10□	**Plant Related**									
□F	10□	I□ta□gib□ P□□t	I□TP□T	1□□□□□□	□□□□□□	1□□1□□	□□□□□□	□□□	1□□□□□	□1□	□□□□0
□F	10□	Tra□□□ i□□io□ P□□t i□ □er□i□e	TR□□P□T	0	0	0	0	0	0	0	0
□F	10□	Di□trib□tio□ P□□t i□ □er□i□e	DI□TP□T	10□□1□□□□□	□□□□□□□□	1□□□□□□□	□□1□□□□□	□□□□□□	1□□□□□□□	□0□□□□	1□□□□1□
□F	10□	Ge□era□P□□t i□ □er□i□e	GE□□P□T	□□□□0□□	1□□□1□1	□□□1□□	□□□11□	1□□□1	□0□□□□	1□□□□	□□0□0
□F	10□	Tota□E□e□tri□P□□t I□ □er□i□e	TOTP□T	11□□□□□0□	□□□□□□□□	1□□□□01□	□□□□□1□□	□□□□00	1□□0□□0□□	□□□□□□	1□□□□□
□F	110										
□F	111	Di□trib□tio□ P□□t Ex□□□ □et Retire□ e□t	DI□TP□TX□R	10□□1□□1□□	□□□□□□□□	1□□□□□□□	□□1□□1□□□	□□□□□□	1□□□□□1□□	□0□□□□	1□□□□□
□F	11□	Tota□Tra□□□ i□□io□a□d Di□trib□tio□P□□t	TDP□T	10□□1□□□□□	□□□□□□□□	1□□□□□□□	□□1□□□□□	□□□□□□	1□□□□□□□	□0□□□□	1□□□□1□
□F	11□	Tota□Di□trib□tio□a□d Ge□era□P□□t	DGP□T	11□0□□□□□	□□□11□□□	1□□□□□□□	□□□0□□□1□	□□□1□□	1□□□□11□	□□□□□1	1□□□□□
□F	11□	Rate Ba□e	R□TEB□□E	□□□□□□□□	□□□□□□□□	1□1□□□□□	1□□0□□□□0	□□□0□□	1□1□□□□□	□□□□□□	1□□□□□
□F	11□										
□F	11□	□□□o□□t □□0	P□T□□□0	□□□1□□	□1□0□1	□□□0□	10□□□□	□□□	1□□1□□	□□□	□□□
□F	11□	□□□o□□t □□1	P□T□□□1	□□□□□□	□□□□□	□□□□00	□0□□□□	1□□□□	□□□□□	□□□□	1□□□
□F	11□	□□□o□□t □□□	P□T□□□□	1□□0□□□□0	□□□□□□	1□□□□0□	□□□□1□□	10□□□□	□□□□00	1□□0□□	□□□□
□F	11□	□□□o□□t □□□	P□T□□□□	1□□□□□□0□	□□□□□1	□0□□□□	□□□□□□	□□□□	1□0□□□	□□□1	1□□□□
□F	1□0	□□□o□□t □□□	P□T□□□□	□□□□□□0□	1□□□□□□	□□□□□□	□□□□0□1	1□□□01	□□□□□□	1□□1□□	□1□□□
□F	1□1	□□□o□□t □□□	P□T□□□□	1□0□□□□□	□□□□□□	1□□□□□1	1□0□□□1	□□□□	1□□□□□	□□0□□	1□□□□0
□F	1□□	□□□o□□t □□□	P□T□□□□	□□□□□□1□	1□1□□□□□	□0□□□1□	□1□□0□	1□□□1	□□□□0□	1□□□□	□□□□
□F	1□□	□□□o□□t □□□	P□T□□□□	□□0□□□	□0□□□□	1□□□111	□□□□□□	0	0	0	□□□□
□F	1□□	□□□o□□t □□□	P□T□□□□	□0□□□□	□□0□□□1	□1□□□□	1□□□1□1	□□□	□□□□	0	0
□F	1□□	□□□o□□t □□0	P□T□□□0	□□□□1□0	□□□□□□0	□□□□□□	□□□□□□	1□□□1	1□□□0□	1□□	0
□F	1□□	□□□o□□t □□1	P□T□□□1	1□□□□□	10□□0□	1□□0□	1□□□□	0	0	0	□□□
□F	1□□	□□□o□□t □□□	P□T□□□□	□□□□□□	0	0	0	0	0	0	□□□□□
□F	1□□	Di□trib□tio□ O□erhead P□□t i□ □er□i□e	OHDI□T	□□□□□□□0□	□0□□□□□□	□□0□□□1	□□0□□□0	□□□□□□	□□□□00□	□□□0□□	□0□□□
□F	1□□	Di□trib□tio□ □□dergro□□d P□□t i□ □er□i□e	□GDI□T	□□□□□□□□	1□□□□□□□	□□1□□0□	□0□□□□□	1□□□□□	□□0□□□	□□□□□	□□□□□
□F	1□0	□□□o□□t□ □□0 □ □□1	P□T□□□01	□0□□□1	1□0□□□	□□□□0□	□0□□□□	□□□□	□0□□□□	□□□□	1□□□0
□F	1□1	□□□o□□t□ □□1 □ □□□	P□T□□□1□	□0□□□0	10□□0□	1□□0□	1□□□□	0	0	0	□□□□
□F	1□□										
□F	1□□	Re□de□tia□	DP□TRE□	□□□□□1□□	□□□□□1□□	0	0	0	0	0	0
□F	1□□	Re□de□tia□Heati□g	DP□TRH	□□□□0□□	0	□□□□0□□	0	0	0	0	0
□F	1□□	Ge□era□□er□i□e	DP□TG□	1□□□□□0□□	0	0	1□□□□□0□□	0	0	0	0
□F	1□□	Pri□ ar□Di□trib□tio□	DP□TPRID	□□□□1□	0	0	0	□□□□1□	0	0	0
□F	1□□	High Te□□io□	DP□THT	□□□□□□□	0	0	0	0	□□□□□□□	0	0
□F	1□□	E□e□tri□Pro□□□io□	DP□TEP	□□□□□□	0	0	0	0	0	□□□□□□	0
□F	1□□	□ighti□g	DP□T□C□□T	□0□□□1	0	0	0	0	0	0	□0□□□1
□F	1□0										
□F	1□1										
□F	1□□										
□F	1□□										
□F	1□□										
□F	1□□										
□F	1□□										
□F	1□□										
□F	1□□										
□F	1□0										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
□F	1□1	**ALLOCATION FACTOR TABLE CONTINUED**									
□F	1□□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
□F	1□□										
□F	1□□	**Production Expense Related**									
□F	1□□	□□□o□□t □□□	OX□□□□	1□00□□□1□	□□□□□□1	1□□□□□□	1□□□□□0	1□01□	□□□□□1	0	□00
□F	1□□	O□M Ex□e□□e Prod□□tio□ Other	OX□PROD	1□00□□□1□	□□□□□□1	1□□□□□□	1□□□□□0	1□01□	□□□□□1	0	□00
□F	1□□	□a□arie□a□d □ age□Prod□□tio□O□eratio□	□□□□ □GPO	0	0	0	0	0	0	0	0
□F	1□□										
□F	1□□										
□F	1□0	**Transmission Expense Related**									
□F	1□1	Tra□□□ i□□io□ O□eratio□ Ex□e□□e	OX□TR□□	1□□□□0□	10□□□□□	□□□□□□	□1□□1□	□1□	□1□11□	□□□	□□
□F	1□□	Tra□□□ i□□io□ Mai□te□a□□e Ex□e□□e	MX□TR□□	0	0	0	0	0	0	0	0
□F	1□□	Tra□□□ i□□io□ □a□arie□ □ age□ □□□o□□t□ □11-□□□	□□□□ □GTO	0	0	0	0	0	0	0	0
□F	1□□	Tra□□□ i□□io□ □a□arie□ □ age□ □□□o□□t□ □□□-□□□	□□□□ □GTM	0	0	0	0	0	0	0	0
□F	1□□										
□F	1□□										
□F	1□□	**Distribution Expense Related**									
□F	1□□	□□□o□□t □□0	OX□□□0	1□□0□	□□□	1□□	□0□	□	11□	□	1□
□F	1□□	□□□o□□t □□1	OX□□□1	0	0	0	0	0	0	0	0
□F	1□0	□□□o□□t □□□	OX□□□□	□1□	□1□	10□	1□1	□	□1□	11	□
□F	1□1	□□□o□□t □□□	OX□□□□	1□□□1□	□□□□1	□□□1□	□□□□□	10□	□□1□□	10□	□□1
□F	1□□	□□□o□□t □□□	OX□□□□	1□□□□□	□□□□□	1□□□□	□□□□□	□□	□□□0□	11□	1□□
□F	1□□	□□□o□□t □□□	OX□□□□	0	0	0	0	0	0	0	0
□F	1□□	□□□o□□t □□□	OX□□□□	□□□□1	□□□□□	□□□□	1□1□1	□□	□□□	□	0
□F	1□□	□□□o□□t □□□	OX□□□□	1□□□0□	11□□□□	1□□□□	□	□□	0	110	
□F	1□□	□□□o□□t □□□	OX□□□□	□0□□□1	□□□□□□	1□□00□	1□□0□□	□□1	1□□1□□	□□□	1□□□
□F	1□□	□□□o□□t □□□	OX□□□□	□□□□□	1□□□□	□□□	□□1	1□	□□□	□□	□□
□F	1□□	□□□o□□t □□1	MX□□□1	□□□□□	□□□□□	□□0	1□□11	□□	1□□□1	□□	□□
□F	1□□	□□□o□□t □□□	MX□□□□	1□□□□□	□□□□0	□□□0□	□□□0□	1□□	□□□1□	□□□	100
□F	1□0	□□□o□□t □□□	MX□□□□	□0□□□□	10□□□10	□□□0□□	□□□11□	1□□□0	□□□□□	1□□□0	□□□□
□F	1□1	□□□o□□t □□□	MX□□□□	□□□1□□	1□□□1□	□□1□□	□□1□□	□□□	□□1□□	□0□	□□□
□F	1□□	□□□o□□t □□□	MX□□□□	□□□□□	1□□□□	□□□	□□□	0	0	0	1□
□F	1□□	□□□o□□t □□□	MX□□□□	1□□□□	0	0	0	0	0	0	1□□□
□F	1□□	□□□o□□t □□□	MX□□□□	0	0	0	0	0	0	0	0
□F	1□□	□□□o□□t □□□	MX□□□□	□0□□□□	10□□□1	□□□1□	□□0□□	10□	□□□□□	1□□	□□□
□F	1□□	O□M □□□o□□t□ □□□1-□□□	OX□DI□T	1□□□□□□	□1□□1□	1□□□□□	□□□□□□	□□□	1□□□□□	□□0	□11□
□F	1□□	O□M □□□o□□t□ □□□1-□□□	MX□DI□T	□□□□□0□	1□0□1□□	□□□□□□	□□□01□	1□□□1	□0□□□□	1□□□□	□□□□
□F	1□□										
□F	1□□										
□F	1□0										
□F	1□1										
□F	1□□										
□F	1□□										
□F	1□□										
□F	1□□										
□F	1□□										
□F	1□□										
□F	1□□										
□F	□00										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
□F	□01	**ALLOCATION FACTOR TABLE CONTINUED**									
□F	□0□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
□F	□0□										
□F	□0□	**Customer Distribution Expense Related**									
□F	□0□	□□□o□□t □0□	OX□□0□	□□□	□□□	10□	1□0	□	□□	1	0
□F	□0□	□□□o□□t □0□	OX□□0□	10□□□0□	□□□□□□	1□□□□1	□□□□□	□□□	□□□□□	□□	□□□
□F	□0□	□□□o□□t □0□	OX□□0□	□□□□□□	□□□□□□	□□□□□	□□□□□	1□	□□□	0	□
□F	□0□	O□M □□□o□□t□ □0□-□0□	OX□C□	1□□□10□	1□0□□□1	□1□□1□	1□□□□□	□□□	□□□□□	□□	□□0
□F	□0□										
□F	□10	□□□o□□t□0□	OX□□0□	1□□□11	1□□□0□	□□□□□	□□□	□	□□	0	□□
□F	□11	□□□o□□t□0□	OX□□0□	1□□0□	1□0□□	1□□	1□□	0	□	0	11
□F	□1□	□□□o□□t□10	OX□□10	1□000	□□0	11□	□1	0	□	0	□
□F	□1□	O□M □□□o□□t□ □0□-□10	OX□C□	□1□□1□	1□□0□0	□□□□□	□□□	□	□1	0	□□
□F	□1□	□□□o□□t□ □01-□10	X□C□C□	1□□□□□□	1□□□□□0	□□□0□□	1□□□1□	□□0	□□□0□	□□	□□□
□F	□1□										
□F	□1□	Tota□O□M □e□□ P□r□ha□ed Po□er	OMXPP	1□001□□□	□□□□□□□	1□□□□□□	1□□□□□0	□□□□□	10□□□□□	□□□□□	10□□1□
□F	□1□	Tota□O□M □e□□ PP □e□□Pa□ro□□e□□Pe□□io□	OMXPPPP	□□□□□□0	□□□□□□□	10□□□□□	1□□□0□1	□□□□□	□□□□0□	□□□□□	□□□□□
□F	□1□										
□F	□1□	**Salaries and Wages Expense Related**									
□F	□□0	□a□arie□ □ □ age□ □□□o□□t□ □□1-□□□	□□□□ □GDO	□□□□1□	1□□□□□	□□01□	□□□□□	□□	□□0□□	□□	□□0
□F	□□1	□a□arie□ □ □ age□ □□□o□□t□ □□1-□□□	□□□□ □GDM	□□□□01	□0□1□□	10□□□□	1□□□□□	□□□□	11□□□□	□□□□	1□□□
□F	□□□	□a□arie□ □ □ age□ □□□o□□t□ □0□-□0□	□□□□ □GC□	□□□10□	□□□□0□	□□□□□	□□□□0	□□□□	1□□1□	1□	□1□
□F	□□□	□a□arie□ □ □ age□ □□□o□□t□ □0□-□10	□□□□ □GC□	1□□□□	1□□□□	□□□	□0	0	□	0	□
□F	□□□	□a□arie□ □ □ age□Ex□□di□g □d□i□ □ Ge□	□□□□ □GX□G	1□□□□□0	□□□1□□	1□□□□□	□□□1□0	□0□	1□□□□□	□□□□	1□□□□
□F	□□□	Tota□□a□arie□a□d □ age□Ex□e□□e	□□□□ □GE□	1□□□□□□	10□□□□□	□□□□□□	□□□□□□	□□1	1□□□□□	□□□□	1□□□□
□F	□□□										
□F	□□□	Ba□e Taxab□e I□□o□e	EBT	1□1□□1□	1□□□□□1	□□□□□□□	□□□□□□	□0□	1□□□□1	□□1□□	□0□0
□F	□□□										
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
F	1	**REVENUES AND BILLING DETERMINANTS**									
F											
F		Base Rate Revenue	E RE	1 1	1	1 1	01		1	0	0
F											
F		Residential	RE RE	1	1	0	0	0	0	0	0
F		Residential Heating	RE RH	1 1	0	1 1	0	0	0	0	0
F		General Service	RE G	01	0	0	01	0	0	0	0
F		Primary Distribution	RE PRID		0	0	0		0	0	0
F		High Tension	RE HT	1	0	0	0	0	1	0	0
F	0	Electric Propulsion	RE EP	0	0	0	0	0	0	0	0
F	1	Lighting	RE C T	0	0	0	0	0	0	0	0
F											
F		RRH	RE RRH	1 0 1 1	1	1 1	0	0	0	0	0
F		GPDHT	RE GPDHT	1	0	0	01	0	1	0	0
F		PDHT	RE PDHT	1 1	0	0	0	0	1	0	0
F											
F		Calculated Rate Revenue	C IMRE	1 1	1	1	1	1	0	1	0 0
F											
F		Capitalized	C P TOC	0	0	0	1	1	1	10	10 0
F	0										
F	1										
F		**PRESENT REVENUES/EXPENSES FROM SALES INPUT**									
F											
F		Total Base of Electric Revenue		1		1	1	1	1	00	01
F		Base of Electric Revenue - Distribution		1 1	1	1 1	01		1	0	0
F		Base of Electric Revenue - Year Deficiency		1	1 1				1	1	0
F											
F											
F											
F	0	Base of Electric Revenue - Transmission		1 1	11 1						
F	1										
F		**BILLING DETERMINATE INPUTS**									
F		Number of Customer Bills	CH F	0	1 0	0	1	0	1		1 0
F		Annual Mwh Base Meter	CH F	0	11 0 1	0	0	0 10	1	0	1 0
F		Annual Mwh - Billed		0	0	0	1		1	1	0
F											
F											
F		**RATE OF RETURN**									
F	0	Rate of Return Earned	CH F								
F	1										
F											
F											
F											
F											
F											
F											
F											
F	00										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
□P	1	**ALLOCATION PROPORTIONS TABLE**									
□P	□	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
□P	□										
□P	□										
□P	□	DEM□□D - PROD□CTIO□ RE□□TED									
□P	□	De□a□d Prod□□tio□	DPROD	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	□										
□P	□										
□P	□										
□P	10										
□P	11	DEM□□D - TR□□□MI□□IO□ RE□□TED									
□P	1□	De□a□d Tra□□□i□□io□ □1 Coi□□ide□t Pea□□	DTR□□	1□00000	0□□1□1□	0□0□□□□	0□□1□□□	0□00□□□	0□□□□□□	0□00□□□	0□000□□
□P	1□										
□P	1□	De□a□d Tra□□□i□□io□ □Re□e□□e□	DTR□□R	1□00000	0□□□□□□	0□1□□□□	0□1□□0□	0□00□□□	0□11□□□	0□00□□0	0□000□□
□P	1□										
□P	1□										
□P	1□										
□P	1□										
□P	1□										
□P	□0	DEM□□D - DI□TRIB□TIO□ RE□□TED □□o□-Coi□□ide□t Pea									
□P	□1	De□a□d Di□trib□tio□ Pri□ar□High Te□□io□	DDI□PHT	1□00000	0□□□□□□	0□1□□□□	0□1□□□□	0□00□□□	0□□□11□	0□01□□□	0□00□□□
□P	□□	De□a□d Di□trib□tio□ Pri□ar□O□erhead □i□e□	DDI□TPO□	1□00000	0□□□□□1□	0□1□□□0	0□□□0□□	0□0100□	0□00000	0□00000	0□00□□□
□P	□□	De□a□d Di□trib□tio□ Pri□ar□□□dergro□□d □i□e□	DDI□TP□□	1□00000	0□□□□□1□	0□1□□□0	0□□□0□□	0□0100□	0□00000	0□00000	0□00□□□
□P	□□										
□P	□□	De□a□d Di□trib□tio□ □e□o□dar□O□erhead □i□e□	DDI□T□O□	1□00000	0□□□1□□	0□1□□□□	0□□□□□□	0□00000	0□00000	0□00000	0□00□□□
□P	□□	De□a□d Di□trib□tio□ □e□o□dar□□□dergro□□d □i□e□	DDI□T□□□	1□00000	0□□□1□□	0□1□□□□	0□□□□□□	0□00000	0□00000	0□00000	0□00□□□
□P	□□	De□a□d Di□trib□tio□O□erhead □i□e Tra□□for□er□	DDI□T□OT	1□00000	0□□□1□□	0□1□□□□	0□□□□□□	0□00000	0□00000	0□00000	0□00□□□
□P	□□	De□a□d Di□trib□tio□ □□dergro□□d □i□e Tra□□for□er□	DDI□T□□T	1□00000	0□□□1□□	0□1□□□□	0□□□□□□	0□00000	0□00000	0□00000	0□00□□□
□P	□□										
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
P	1	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
P		**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
P											
P		**ENERGY**									
P		E erg Re e e at ro-for a ad ted e e	E ERG 1	1 00000	0	0 1 1	0 1 1	0 00101	0 0	0 00000	0 000 0
P		E erg Meter M h a e	E ERG	1 00000	0 1	0 0	0 0	0 00	0	0 01	0 00
P											
P											
P											
P	0										
P	1										
P											
P											
P											
P		**CUSTOMER**									
P		- C t Di t e o dar OH i e CP	CDI T O	1 00000	0 1	0 1	0	0 00000	0 00000	0 00000	0 00
P		- C t Di t e o dar G i e CP	CDI T	1 00000	0 1	0 1	0	0 00000	0 00000	0 00000	0 00
P		- C t Di t e o dar Po e To er Fixt re	CDI T O C	1 00000	0	0 11	0 0 0	0 00000	0 00000	0 00000	0 0 1 0
P		- C t Di t e o dar Co d tor De i e	CDI T C	1 00000	0	0 11	0 0 0	0 00000	0 00000	0 00000	0 0 1 0
P	0										
P	1	-er i e	C ER ICE	1 00000	0 1	0 0 1	0	0 000	0 00 1	0 00000	0 00000
P		0-Meter	CMETER	1 00000	0	0 10	0 1	0 00 1	0 0	0 000	0 00000
P		1-I ta atio o C to er Pre i e	C TPREM	1 00000	0	0 11	0 0 0	0 00000	0 00000	0 00000	0 0 1 0
P		-treet ighti g ig a te	C IGHT	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	1 00000
P											
P		C to er De o it	C TDEP	1 00000	0 0 1	0 0	0 11	0 00	0 0	0 00000	0 00000
P											
P											
P		0-C to er Re ord a d Co e tio	C TREC	1 00000	0 1	0 11	0 0 0	0 00	0 0	0 000	0 00
P	0	0-Mi e a eo C to er o t	C TC M	1 00000	0 0	0 11 0	0 0 1	0 000	0 001	0 0000	0 00
P	1	0-C to er i ta e	C T T	1 00000	0	0 1	0 0	0 0000	0 00	0 00001	0 001
P		0-I for atio a a d I tr tio a d erti g	C T D T	1 00000	0 0	0 11 0	0 0 1	0 000	0 001	0 0000	0 00
P		10-Mi e a eo C to er er i e	C TC M	1 00000	0 0	0 11 0	0 0 1	0 000	0 001	0 0000	0 00
P		1 1-Mi e a eo a e Ex e e	C T E	1 00000	0 00000	0 00000	0 0	0 01	0 1	0 00000	0 00000
P											
P		ber of Bi	C TBI	1 00000	0 0	0 11 0	0 0 1	0 000	0 001	0 0000	0 00
P		ber of C to er	C T	1 00000	0 0	0 11 0	0 0 1	0 000	0 001	0 0000	0 00
P		ber of Re ide tia C to er	C TRE	1 00000	0	0 1	0	0 00000	0 00000	0 00000	0 00000
P		ber of Co er ia a d I d tria C to er	C TCI	1 00000	0 00000	0 00000	0 0	0 00 0	0 01 0	0 00000	0 00000
P	0										
P	1	Tra it Chargi g - G	CTCRE R	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000
P		Tra it Chargi g - PD HT	CTCRE CI	1 00000	0 00000	0 00000	0 00000	0 0	0 0	0 00000	0 00000
P											
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P											
P	100										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
□P	101	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
□P	10□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
□P	10□										
□P	10□	**Plant Related**									
□P	10□	I□ta□gib□ P□□t	I□TP□T	1□00000	0□□1 □□□	0□1 □1 □□	0□1 □□□□	0□00 □□□	0□1 □0 □□	0□00 □□□	0□01 □1 □
□P	10□	Tra□□□ i□□io□ P□□t i□ □er□i□e	TR□□P□T	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	10□	Di□trib□tio□ P□□t i□ □er□i□e	DI□TP□T	1□00000	0□□0 □□□	0□1 □□0 □	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□□	0□01 □□□
□P	10□	Ge□era□P□□t i□ □er□i□e	GE□ □P□T	1□00000	0□□□□0 □	0□1 □□□□	0□1 □□□□	0□00 □□□	0□10 □□□	0□00 □□□	0□010 □□
□P	10□	Tota□E□e□tri□ P□□t I□ □er□i□e	TOTP□T	1□00000	0□□0 □□□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□1	0□01 □□1
□P	110										
□P	111	Di□trib□tio□ P□□t Ex□□□ □□et Retire□ e□t	DI□TP□TX□R	1□00000	0□□0 □□□	0□1 □□0 □	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□□	0□01 □□□
□P	11□	Tota□Tra□□□ i□□io□ a□d Di□trib□tio□ P□□t	TDP□T	1□00000	0□□0 □□□	0□1 □□0 □	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□□	0□01 □□□
□P	11□	Tota□Di□trib□tio□ a□d Ge□era□P□□t	DGP□T	1□00000	0□□0 □□0	0□1 □□□0	0□1 □□□□	0□00 □□□	0□1 □□00	0□00 □□□	0□01 □□□
□P	11□	Rate Ba□e	R□TEB□□E	1□00000	0□□1 □□□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□□	0□01 □□□
□P	11□										
□P	11□	□□□o□□t □□0	P□T□□□0	1□00000	0□□□□□□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□□□11□	0□01 □□□	0□00 □□□
□P	11□	□□□o□□t □□1	P□T□□□1	1□00000	0□□□□□□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□□□11□	0□01 □□□	0□00 □□□
□P	11□	□□□o□□t □□□	P□T□□□□	1□00000	0□□□□□□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□□□11□	0□01 □□□	0□00 □□□
□P	11□	□□□o□□t □□□	P□T□□□□	1□00000	0□□□1 □□	0□1 □□□□	0□1 □□□□	0□00 □00	0□1 □0 □□	0□00 □□□	0□01 □1 □
□P	1□0	□□□o□□t □□□	P□T□□□□	1□00000	0□□□1 □□	0□1 □□□□	0□1 □□□□	0□00 □00	0□1 □0 □□	0□00 □□□	0□01 □1 □
□P	1□1	□□□o□□t □□□	P□T□□□□	1□00000	0□□0 □0 □	0□1 □□□□	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□0	0□011 □□
□P	1□□	□□□o□□t □□□	P□T□□□□	1□00000	0□□0 □0 □	0□1 □□□□	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□0	0□011 □□
□P	1□□	□□□o□□t □□□	P□T□□□□	1□00000	0□□□1 □□	0□1 □□□□	0□□□□□□	0□00000	0□00000	0□00000	0□00 □□□
□P	1□□	□□□o□□t □□□	P□T□□□□	1□00000	0□□□□□1	0□0 □1 □□	0□□□□□□	0□000 □□	0□00 □□1	0□00000	0□00000
□P	1□□	□□□o□□t □□0	P□T□□□0	1□00000	0□□□□□□	0□10 □□□	0□1 □□□□	0□00 □□1	0□0 □□□□	0□000 □□	0□00000
□P	1□□	□□□o□□t □□1	P□T□□□1	1□00000	0□□□□□□	0□11 □□□	0□0 □□□0	0□00000	0□00000	0□00000	0□0 □1 □0
□P	1□□	□□□o□□t □□□	P□T□□□□	1□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	1□00000
□P	1□□	Di□trib□tio□ O□erhead P□□t i□ □er□i□e	OHDI□T	1□00000	0□□□1 □□	0□1 □□□□	0□1 □□□□	0□00 □00	0□1 □0 □□	0□00 □□□	0□01 □1 □
□P	1□□	Di□trib□tio□ □□dergro□□d P□□t i□ □er□i□e	□GDI□T	1□00000	0□□0 □0 □	0□1 □□□□	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□0	0□011 □□
□P	1□0	□□□o□□t□ □□0 □ □□1	P□T□□□01	1□00000	0□□□□□□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□□□11□	0□01 □□□	0□00 □□□
□P	1□1	□□□o□□t□ □□1 □ □□□	P□T□□□1 □	1□00000	0□11 □□□	0□01 □□□	0□01 □□□	0□00000	0□00000	0□00000	0□□□□1 □
□P	1□□										
□P	1□□	Re□ide□tia□	DP□TRE□	1□00000	1□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	1□□	Re□ide□tia□Heati□g	DP□TRH	1□00000	0□00000	1□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	1□□	Ge□era□□er□i□e	DP□TG□	1□00000	0□00000	0□00000	1□00000	0□00000	0□00000	0□00000	0□00000
□P	1□□	Pri□ ar□Di□trib□tio□	DP□TPRID	1□00000	0□00000	0□00000	0□00000	1□00000	0□00000	0□00000	0□00000
□P	1□□	High Te□□io□	DP□THT	1□00000	0□00000	0□00000	0□00000	0□00000	1□00000	0□00000	0□00000
□P	1□□	E□e□tri□ Pro□□□io□	DP□TEP	1□00000	0□00000	0□00000	0□00000	0□00000	0□00000	1□00000	0□00000
□P	1□□	□ighti□g	DP□T□C□□T	1□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	1□00000
□P	1□0										
□P	1□1										
□P	1□□										
□P	1□□										
□P	1□□										
□P	1□□										
□P	1□□										
□P	1□□										
□P	1□□										
□P	1□0										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
□P	1□1	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
□P	1□□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
□P	1□□										
□P	1□□	**Production Expense Related**									
□P	1□□	□□□o□□t □□□	OX□□□□	1□00000	0□□□□□□	0□1 □□□1	0□1 □□□1□	0□00101	0□0□□□□	0□00000	0□000□0
□P	1□□	O□M Ex□e□□e Prod□□tio□ Other	OX□PROD	1□00000	0□□□□□□	0□1 □□□1	0□1 □□□1□	0□00101	0□0□□□□	0□00000	0□000□0
□P	1□□	□a□arie□a□d □ age□Prod□□tio□O□eratio□	□□□□ □GPO	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	1□□			0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	1□□										
□P	1□0	**Transmission Expense Related**									
□P	1□1	Tra□□□ i□□io□O□eratio□Ex□e□□e	OX□TR□□	1□00000	0□□□□□□	0□1 □□□□	0□1 □□0□	0□00 □□□	0□11 □□□	0□00 □□0	0□000□□
□P	1□□	Tra□□□ i□□io□ Mai□te□a□□e Ex□e□□e	MX□TR□□	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	1□□	Tra□□□ i□□io□ □a□arie□□ □ age□ □□□o□□t□ □11-□□□	□□□□ □GTO	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	1□□	Tra□□□ i□□io□ □a□arie□□ □ age□ □□□o□□t□ □□□-□□□	□□□□ □GTM	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	1□□										
□P	1□□										
□P	1□□	**Distribution Expense Related**									
□P	1□□	□□□o□□t □□0	OX□□□0	1□00000	0□□0 □□□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□0□□□□	0□00 □0□	0□011 □□
□P	1□□	□□□o□□t □□1	OX□□□1	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	1□0	□□□o□□t □□□	OX□□□□	1□00000	0□□□□□□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□□□11□	0□01 □□□	0□00 □□□
□P	1□1	□□□o□□t □□□	OX□□□□	1□00000	0□□□1 □□	0□1 □□□□	0□1 □□□□	0□00 □00	0□1 □0□□	0□00 □□□	0□01 □1□
□P	1□□	□□□o□□t □□□	OX□□□□	1□00000	0□□0 □0□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□0	0□011 □□
□P	1□□	□□□o□□t □□□	OX□□□□	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	1□□	□□□o□□t □□□	OX□□□□	1□00000	0□□□□□□	0□10 □□□	0□1 □□□□	0□00 □□1	0□0 □□□□	0□000 □□	0□00000
□P	1□□	□□□o□□t □□□	OX□□□□	1□00000	0□□□0 □□	0□11 □0□	0□0 □1 □□	0□000 □□	0□001 □□	0□0000□	0□00 □□□
□P	1□□	□□□o□□t □□□	OX□□□□	1□00000	0□□0 □□□	0□1 □□0□	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□□	0□01 □□□
□P	1□□	□□□o□□t □□□	OX□□□□	1□00000	0□□0 □□□	0□1 □□0□	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□□	0□01 □□□
□P	1□□	□□□o□□t □□1	MX□□□1	1□00000	0□□□□□□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□□□11□	0□01 □□□	0□00 □□□
□P	1□□	□□□o□□t □□□	MX□□□□	1□00000	0□□□□□□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□□□11□	0□01 □□□	0□00 □□□
□P	1□0	□□□o□□t □□□	MX□□□□	1□00000	0□□□1 □□	0□1 □□□□	0□1 □□□□	0□00 □00	0□1 □0□□	0□00 □□□	0□01 □1□
□P	1□1	□□□o□□t □□□	MX□□□□	1□00000	0□□0 □0□	0□1 □□□□	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□0	0□011 □□
□P	1□□	□□□o□□t □□□	MX□□□□	1□00000	0□□□1 □□	0□1 □□□□	0□□□□□□	0□00000	0□00000	0□00000	0□00 □□□
□P	1□□	□□□o□□t □□□	MX□□□□	1□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	1□00000
□P	1□□	□□□o□□t □□□	MX□□□□	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□P	1□□	□□□o□□t □□□	MX□□□□	1□00000	0□□0 □□□	0□1 □□0□	0□1 □□□□	0□00 □□□	0□1 □□□□	0□00 □□□	0□01 □□□
□P	1□□	O□M □□□o□□t□ □□□1-□□□	OX□DI□T	1□00000	0□□□□□□	0□1 □0□□	0□1 □□□□	0□00 □□□	0□11 □1□	0□00 □□□	0□01 □1□
□P	1□□	O□M □□□o□□t□ □□□1-□□□	MX□DI□T	1□00000	0□□0 □□0	0□1 □□□□	0□1 □□□1	0□00 □□□	0□1 □□□1	0□00 □□□	0□01 □□0
□P	1□□										
□P	1□□										
□P	1□0										
□P	1□1										
□P	1□□										
□P	1□□										
□P	1□□										
□P	1□□										
□P	1□□										
□P	1□□										
□P	1□□										
□P	□00										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
□P	□01	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
□P	□0□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
□P	□0□										
□P	□0□	**Customer Distribution Expense Related**									
□P	□0□	□□□o□□t □0□	OX□□0□	1□00000	0□□□□□□	0□10□□□	0□1□□□□	0□00□□1	0□0□□□□	0□000□□	0□00000
□P	□0□	□□□o□□t □0□	OX□□0□	1□00000	0□□□□1□	0□11□□□	0□0□□□0	0□00□□□	0□0□□□□	0□000□□	0□00□□□
□P	□0□	□□□o□□t □0□	OX□□0□	1□00000	0□□□□□□	0□1□□□□	0□0□□□□	0□000□□	0□01000	0□00000	0□0000□
□P	□0□	O□M □□□o□□t□ □0□-□0□	OX□C□	1□00000	0□□□1□□	0□1□1□□	0□0□□□□	0□00□00	0□0□□1□	0□000□□	0□00□□□
□P	□0□										
□P	□10	□□□o□□t□0□	OX□□0□	1□00000	0□□□□□□	0□1□□□□	0□0□□□□	0□0000□	0□00□□□	0□00001	0□001□□
□P	□11	□□□o□□t□0□	OX□□0□	1□00000	0□□□0□□	0□11□0□	0□0□1□□	0□000□□	0□001□□	0□0000□	0□00□□□
□P	□1□	□□□o□□t□10	OX□□10	1□00000	0□□□0□□	0□11□0□	0□0□1□□	0□000□□	0□001□□	0□0000□	0□00□□□
□P	□1□	O□M □□□o□□t□ □0□-□10	OX□C□	1□00000	0□□□□□□	0□1□□□□	0□0□□□□	0□00010	0□00□□□	0□00001	0□00□□□
□P	□1□	□□□o□□t□ □01-□10	X□C□C□	1□00000	0□□□□1□	0□1□0□0	0□0□□□□	0□00□□□	0□0□□11	0□000□□	0□00□□□
□P	□1□										
□P	□1□	Tota□O□M □e□□ P□r□ha□ed Po□er	OMXPP	1□00000	0□□□□□0	0□1□□□□	0□1□□□0	0□00□□□	0□10□□□	0□00□□□	0□010□0
□P	□1□	Tota□O□M □e□□ PP □e□□Pa□ro□□e□□Pe□□io□	OMXPPPP	1□00000	0□□□1□□	0□1□□□□	0□1□□□□	0□00□□1	0□10□□□	0□00□□0	0□010□□
□P	□1□										
□P	□1□	**Salaries and Wages Expense Related**									
□P	□□0	□a□arie□ □ □ age□ □□□o□□t□ □□1-□□□	□□□□ □GDO	1□00000	0□□0□□□	0□1□□□□	0□1□□□□	0□00□□□	0□0□□□□	0□00□0□	0□011□□
□P	□□1	□a□arie□ □ □ age□ □□□o□□t□ □□1-□□□	□□□□ □GDM	1□00000	0□□0□□0	0□1□□□□	0□1□□□0	0□00□0□	0□1□□□□	0□00□□□	0□01□□0
□P	□□□	□a□arie□ □ □ age□ □□□o□□t□ □0□-□0□	□□□□ □GC□	1□00000	0□□□□0□	0□11□□□	0□0□□□□	0□00□□□	0□0□□□□	0□000□□	0□00□□□
□P	□□□	□a□arie□ □ □ age□ □□□o□□t□ □0□-□10	□□□□ □GC□	1□00000	0□□□□□□	0□1□□□□	0□0□001	0□00010	0□00□□□	0□00001	0□00□□□
□P	□□□	□a□arie□ □ □ age□Ex□□di□g □d□ i□ □ Ge□	□□□□ □GX□G	1□00000	0□□□□□□	0□1□□□□	0□1□□0□	0□00□□□	0□10□□□	0□00□□0	0□010□□
□P	□□□	Tota□□a□arie□a□d □ age□Ex□e□□e	□□□□ □GE□	1□00000	0□□□□0□	0□1□□□□	0□1□□□□	0□00□□□	0□10□□□	0□00□□□	0□010□□
□P	□□□										
□P	□□□	Ba□e Taxab□e I□□o□ e	EBT	1□00000	0□□□□□□	-0□0□□□□	0□1□□00	0□001□□	0□0□1□□	-0□001□□	0□0□□□0
□P	□□□										
□P	□□□										
□P	□□0										
□P	□□1										
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
P	1	**REVENUES AND BILLING DETERMINANTS**									
P											
P		Base Rate Revenue		1.00000	0.[illegible]	0.11100	0.1[illegible]	0.00[illegible]1	0.11[illegible]1	0.00[illegible]	0.01[illegible]
P											
P		Residential	RES RES	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		Residential Heating	RES RH	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		General Service	RES G	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
P		Primary Distribution	RES PRID	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
P		High Tension	RES HT	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
P	10	Electric Propulsion	RES EP	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
P	11	Lighting	RES CT	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P											
P		RRH	RES RRH	1.00000	0.[illegible]	0.1[illegible]10	0.00000	0.00000	0.00000	0.00000	0.00000
P		GPDHT	RES GPDHT	1.00000	0.00000	0.00000	0.[illegible]	0.01[illegible]	0.[illegible]	0.00000	0.00000
P		PDHT	RES PDHT	1.00000	0.00000	0.00000	0.00000	0.0[illegible]11	0.[illegible]	0.00000	0.00000
P											
P		Calibrated Rate Base	CALIMRE	1.00000	0.[illegible]1	0.1[illegible]1	0.1[illegible]1	0.00[illegible]	0.0[illegible]01	0.00[illegible]	0.00[illegible]0
P											
P		Capitalization	CAPTOC	1.00000	0.[illegible]0	0.1[illegible]	0.1[illegible]0	0.00[illegible]	0.1[illegible]	0.00[illegible]	0.01[illegible]0
P	10										
P	11										
P		**PRESENT REVENUES/EXPENSES FROM SALES INPUT**									
P											
P		Total Base of Electric Revenue		1.00000	0.[illegible]1	0.11[illegible]0	0.1[illegible]	0.00[illegible]0	0.111[illegible]	0.00[illegible]	0.01[illegible]
P		Base of Electric Revenue - Distribution		1.00000	0.[illegible]	0.11100	0.1[illegible]	0.00[illegible]1	0.11[illegible]1	0.00[illegible]	0.01[illegible]
P		Base of Electric Revenue - [illegible]ear Demo[illegible]ing		1.00000	0.[illegible]1[illegible]	0.0[illegible]	0.[illegible]0[illegible]	0.00[illegible]	0.[illegible]	0.01[illegible]	0.00[illegible]
P											
P											
P											
P	10	Base of Electric Revenue - Transmission		1.00000	0.[illegible]	0.1[illegible]	0.1[illegible]0	0.00[illegible]	0.11[illegible]	0.00[illegible]0	0.000[illegible]
P	11										
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
D	1	**ALLOCATED DIRECT ASSIGNMENTS**									
D		**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**									
D											
D		**Net Write-Offs**									
D		Re ide tia	RE RE	0 00 1	0 00 1	0	0	0	0	0	0
D		Re ide tia Heati g	RE RH	1	0	1	0	0	0	0	0
D		Ge era er i e	RE G		0	0		0	0	0	0
D		Pri ar Di trib tio	RE PRID		0	0	0		0	0	0
D		High Te io	RE HT	1 0 0	0	0	0	0	1 0 0	0	0
D	10	E e tri Pro io	RE EP	0	0	0	0	0	0	0	0
D	11	ighti g	RE C T	1	0	0	0	0	0	0	1
D	1										
D	1										
D	1	Tota rite-Off	EXP 0	10 1	0 00 1	1			1 0 0	0	1
D	1										
D	1	Tota rite-Off	EXP 0	1 00000	0	0 1	0 0	0 000	0 01000	0 00000	0 00000
D	1										
D	1	dditio a et rite-Off at C ai ed Rate	EXP 0	0	0	0	0	0	0	0	0
D	1										
D	0										
D	1										
D		**Customer Advances for Construction**									
D		Re ide tia	DP TRE	1	1	0	0	0	0	0	0
D		Re ide tia Heati g	DP TRH	0	0	0	0	0	0	0	0
D		Ge era er i e	DP TG	1 0	0	0	1 0 0	0	0	0	0
D		Pri ar Di trib tio	DP TPRID	1	0	0	0	1	0	0	0
D		High Te io	DP THT		0	0	0	0		0	0
D		E e tri Pro io	DP TEP		0	0	0	0	0		0
D		ighti g	DP T C T	0 1	0	0	0	0	0	0	0 1
D	0										
D	1										
D		C to er d a e for Co tr tio	C T D	0	0	1	0 0	1			0 1
D											
D		C to er d a e for Co tr tio	C T D	1 00000	0 1	0 1	0 1	0 00 00	0 1 1	0 00	0 01 0
D											
D											
D		**Purchase of Receivables**									
D		Re ide tia	RE RE	0	0	0	0	0	0	0	0
D		Re ide tia Heati g	RE RH		0	0		0	0	0	0
D	0	Ge era er i e	RE G	00	0	0	00	0	0	0	0
D	1	Pri ar Di trib tio	RE PRID		0	0	0		0	0	0
D		High Te io	RE HT		0	0	0	0		0	0
D		E e tri Pro io	RE EP	0	0	0	0	0	0	0	0
D		ighti g	RE C T		0	0	0	0	0	0	
D											
D											
D		Tota POR	POR	1 0 0	0	0	00	0	0	0	0
D											
D		Tota POR	POR	1 00000	0	0 0	0	0 00	0 1	0 00000	0 00
D	0										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
□D□	1	**ALLOCATED DIRECT ASSIGNMENTS**									
□D□	□	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**									
□D□	□										
□D□	□	**AVAILABLE**									
□D□	□	Re□ide□tia□	□RE□RE□	0	0	0	0	0	0	0	0
□D□	□	Re□ide□tia□Heati□g	□RE□RH	0	0	0	0	0	0	0	0
□D□	□	Ge□era□□er□i□e	□RE□G□	0	0	0	0	0	0	0	0
□D□	□	Pri□ ar□Di□trib□tio□	□RE□PRID	0	0	0	0	0	0	0	0
□D□	□	High Te□□io□	□RE□HT	0	0	0	0	0	0	0	0
□D□	10	E□e□tri□Pro□□□io□	□RE□EP	0	0	0	0	0	0	0	0
□D□	11	□ighti□g	□RE□□C□□T	0	0	0	0	0	0	0	0
□D□	1□										
□D□	1□										
□D□	1□										
□D□	1□	Tota□□□ai□ab□e	□RE□□□□I□	0	0	0	0	0	0	0	0
□D□	1□										
□D□	1□	Tota□□□ai□ab□e	□RE□□□□I□	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000	0□00000
□D□	1□										
□D□	1□										
□D□	□0										
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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)
RR□	1	**DISTRIBUTION REVENUE REQUIREMENTS**									
RR□	□										
RR□	□	PRE□E□T R□TE□									
RR□	□	----------									
RR□	□	R□TE B□□E		□□□00□□□□	□□□0□□□□□	1□1□1□□□1	1□□□□□□□□	□□□□□0	1□1□□□□□1	□□□□10	1□□□□1□
RR□	□	□ET OPER I□C □PRE□E□T R□TE□□		□□□□□□□□	□□1□□□□	□0□□0□	□□□□□□	1□□0□	□□□□00	1□□□□	□□□□□
RR□	□	R□TE OF RET□R□ □PRE□ R□TE□□		□□□1□	□□1□□	□□□□□	□□0□□	□□□□□	□□□□□	□□□1□	□□□□□
RR□	□	RE□□TI□E R□TE OF RET□R□		1□00	1□1□	0□□□	0□□□	0□□□	0□□□	0□□□	1□□□
RR□	□	□□□E□ RE□E□□E □PRE R□TE□□		1□□□□□1□□	□□□□1□□	1□□□□□1	□□□□01□	□□□□□	1□□□□□□	□□0□□	□□□0□□
RR□	10	RE□E□□E PRE□ R□TE□ □□□□ H		□0□0□□□	□0□0□1□	□0□0□1□	□0□0□□□	□0□0□□□	□0□01□0	□0□01□□	□0□1□□0
RR□	11	RE□E□□E RE□□IRED - □MO□C□□T		□□□□1□	□□□□□1	□□□□□□	□1□1□□□	□1□□□□□	□□□□□□□	□1□1□□□□	□1□1□0□
RR□	1□	□□□E□ RE□ RE□□IRED □□□□		□□□□□1	□0□00	□0□00	□10□□□	□10□□0	□□□□□	□□□1□	□0□00
RR□	1□										
RR□	1□	C□□IMED R□TE OF RET□R□									
RR□	1□	----------									
RR□	1□	C□□IMED R□TE OF RET□R□		□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□
RR□	1□	RET□R□ RE□ FOR C□□IMED ROR		□0□□□□□	□□□□□1□	□□□□□	1□□□□□	□□□□□	□□□1□□	□□□□□	10□□□
RR□	1□	□□□E□ RE□E□□E RE□ C□□IMED ROR - Di□trib□tio□		□0□□□□□□	1□11□□□0□	□□□□1□□	□□□□□□□	10□□□1	□□□□□□□	11□□□□	□□□0□□
RR□	1□	RE□E□□E DEFICIE□C□ □□□E□ RE□		□□□□□□□	1□□□0□□	□□□1□□	□□□□□□0	□□□□□	□0□□□□	□□□□□	□□0□□
RR□	□0	PERCE□T I□CRE□□E RE□□IRED		□□□1□□	□0□□□□	□□□□□□	□□□□□□	□□□□1□	□□□□□□	□□□□□	1□□1□□
RR□	□1	□□□□□□BOO□ED □□ H □□□E□		□□□□□□□0□□	11□□□□0□1	□□□□□□□0	□□□□□□□□	□□0□□10	1□□□□□□□	□□□□□0	1□0□□□
RR□	□□	□□□E□ RE□ RE□□IRED □□□□ H		□0□0□□□	□0□0□□□	□0□0□□1	□0□0□□□	□0□0□□□	□0□01□□	□0□0□□□	□0□1□0□
RR□	□□	RE□E□□E DEFICIE□C□ □□□□ H		□0□01□□	□0□01□□	□0□0□□□	□0□01□0	□0□011□	□0□00□1	□0□010□	□0□0□□□
RR□	□□	□□□E□ RE□E□□E RE□ C□□IMED ROR - E□erg□		1□0□1□□□□	□□□□□1□	1□□0□□□□	1□□□0□□	1□0□□□	□0□□□□	0	□□□
RR□	□□	□□□E□ RE□E□□E RE□ C□□IMED ROR - Tra□□□ i□□io□		1□□□□□□	11□□□0□	□□□□□□	□□□□□□	□□□	□□□□□□	□□□	□□
RR□	□□										
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PECO Exhibit TJJ-3:

Revenue Requirement By Functional Classification

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	1	**SUMMARY AT PRESENT RATES**											
		DEVELOPMENT OF DISTRIBUTION RETURN											
		OPER□TI□G RE□E□□E											
		□a□e□of E□ê□tri□it□- Ba□e	C□□C□□□TED	1□□□□□1□□	□□1□□□□	□□□1□	□1□□□00	0	1□□□□	□□□□□□□	□□0□□□□	□□□□1□□	0
		De□o□ □i□□io□i□g Re□e□□e□	C□□C□□□TED	□□□□1□□	0	□□□□1□□	0	0	0	0	0	0	0
		Other O□erati□g Re□e□□e	C□□C□□□TED	□□□□□□□	□□□□□□□	□□	1□□□□□	0	11	□□□□□□□	□□□□□□□	□□01□	0
		TOT□□ OPER□TI□G RE□E□□E		1□□□□□1□□	□□□□□□□	□□□□□	□□□□0□□	0	1□□0□	□□□□1□0	□□□□□0□	□□□□1□□	0
		OPER□TI□G EXPE□□E□											
	10	O□eratio□ a□d Mai□te□a□□e Ex□e□□e	C□□C□□□TED	□1□□□□□	□□□□1□□	□□□□□	□□□□□□□	0	□□□	□□1□□□□	□01□□0	11□□□□□	0
	11	De□re□iatio□ a□d □□orti□atio□ Ex□e□□e	C□□C□□□TED	□□□□□□□	□□□□□□□	0	10□□□□□	0	□□□□□□□	1□□□□1□	□□□□□□□	□□□□□□□	0
	1□	Taxe□Other Tha□ I□□o□e Taxe□-Ge□era□	C□□C□□□TED	□□□□□□□	1□□□□□	□□□□	□□□□□□	0	1□□	1□□□□□□	1□□□□□□	□□□□□□	0
	1□	Taxe□Other Tha□ I□□o□e Taxe□-Di□trib□tio□ GRT	C□□C□□□TED	□1□□□□□	□□□□□0	□□1	□□□□□□□	0	□0	□□□□□□□	□□□□□□□	1□□□□□	0
	1□	I□□o□e Taxe□	C□□C□□□TED	□1□□□1□□	□1□□□□□□	1□	□□0□□□	0	□□	□1□□□1□□	□1□□□□□□	□1□□□0□	0
	1□	TOT□□ OPER□TI□G EXPE□□E□		1□□□□□□1□	□1□□□□□	□□□□0	□□□□□□□	0	1□0□□	□1□□□□□	□□□□□□□	1□□1□□□□	0
	1□	**OPERATING INCOME (RETURN)**		□□□□□□□	□□□□□□□	□□	10□□□□□	0	□□0	□□□□□□□	1□□□□□0	□0□□□□	0
	1□												
	1□	**DEVELOPMENT OF RATE BASE**											
	1□	E□ê□tri□ Pi□□t i□ □er□i□e	C□□C□□□TED	11□□□□□□0□	□□□10□1□□	0	□0□□□□□□	0	0	□□□10□1□□	□□□□□□□□	1□□□1□□□1	0
	□0	□e□□□ □□□□□ □ated De□re□iatio□	C□□C□□□TED	□□□□□□□□	1□□□□□□□	0	□□□□□□□	0	0	1□□□□□□□	1□0□□□1□	1□1□1□□	0
	□1	P□□□ Rate Ba□e □dditio□□	C□□C□□□TED	□□□0□□	□□□□□□□	□□1□□	□□□□□□0	0	□□01	□□1□□□□	□□□□1□□	□□□□□□	0
	□□	□e□□□ Rate Ba□e Ded□tio□□	C□□C□□□TED	□□□□□□□	□□□□□□□	0	□11□□□	0	0	□□□□□□□	□□1□□1□	1□1□0□□	0
	□□	**TOTAL DISTRIBUTION RATE BASE**	C□□C□□□TED	□□□00□□□	□□□1□□1□□	□□1□□	□□□□□□1□□	0	□□□01	□□□11□□□	□□□□□0□□	1□□□□□□□	0
	□□												
	□□	**DISTRIBUTION RATE OF RETURN (PRESENT)**		□□□1□	□□□□□	□□□1□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□
	□□	**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
	□□												
	□□	**DEVELOPMENT OF PURCHASED POWER RETURN**											
	□□	P□r□ha□ed E□ê□tri□ Re□e□□e□	C□□C□□□TED	1□0□1□□00	0	1□0□1□□00	0	0	0	0	0	0	0
	□0	P□r□ha□ed Po□er O□M Ex□e□□e	C□□C□□□TED	1□00□□□1□	0	1□00□□□1□	0	0	0	0	0	0	0
	□1	P□r□ha□ed Po□er GRT Ex□e□□e	C□□C□□□TED	□□□□01	0	□□□□01	0	0	0	0	0	0	0
	□□	P□r□ha□ed Po□er I□□o□e Taxe□		□0□	0	□0□	0	0	0	0	0	0	0
	□□	P□r□ha□ed Po□er O□erati□g I□□o□e		□□□□□□	0	□□□□□□	0	0	0	0	0	0	0
	□□	Rate Ba□e - P□r□ha□ed P□r Ca□h □ or□i□g Ca□ita□	C□□C□□□TED	□□□1□□	0	□□□1□□	0	0	0	0	0	0	0
	□□	**PURCHASED POWER RATE OF RETURN (PRESENT)**		□□□□□	0□00□	□□□□□	0□00□	0□00□	0□00□	0□00□	0□00□	0□00□	0□00□
	□□												
	□□	**DEVELOPMENT OF TRANSMISSON RETURN**											
	□□	Tra□□□ i□□io□ Re□e□□e□	C□□C□□□TED	1□□□□□□1	1□□□□□□1	0	0	0	1□□□□□1	0	0	0	0
	□□	Tra□□□ i□□io□ O□M Ex□e□□e	C□□C□□□TED	1□□□□0□	1□□□□0□	0	0	0	1□□□□0□	0	0	0	0
	□0	Tra□□□ i□□io□ GRT Ex□e□□e	C□□C□□□TED	11□□□□	11□□□□	0	0	0	11□□□□	0	0	0	0
	□1	Tra□□□ i□□io□ I□□o□e Taxe□		□□□□	□□□□	0	0	0	□□□□	0	0	0	0
	□□	Tra□□□ i□□io□ O□erati□g I□□o□e		□□□□	□□□□	0	0	0	□□□□	0	0	0	0
	□□	Rate Ba□e - Tra□□□ i□□io□ Ca□h □ or□i□g Ca□ita□	C□□C□□□TED	□□□1□	□□□1□	0	0	0	□□□1□	0	0	0	0
	□□	**TRANSMISSION RATE OF RETURN (PRESENT)**		□□□1□	□□□1□	0□00□	0□00□	0□00□	□□□1□	0□00□	0□00□	0□00□	0□00□
	□□												
	□□	**TOTAL OPERATING INCOME (RETURN)**		□□□□□1□	□□0□□□□	□□□□□	10□□□□□	0	1□□0□	□□□□□□□	1□□□□□0	□0□□□□	0
	□□	**TOTAL RATE BASE**		□□□□□□□□	□□□□□0□□	□□□□□1	□□□□□1□□	0	1□□□1□	□□□11□□□	□□□□□□0□□	1□□□□□□□	0
	□□	**COMPOSITE RATE OF RETURN @ CURRENT RATES**		□□□□□	□□□0□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□
	□□												
	□0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
	1	**SUMMARY AT PRESENT RATES**										
		DEVELOPMENT OF DISTRIBUTION RETURN										
		OPERATING RE E										
		ase of Electric - Base	CCCTED			0						
		Depreciation and Amortization Re ee	CCCTED	0		0	0	0	0	0	0	0
		Other Operating Re ee	CCCTED			0						
		TOTAL OPERATING RE E E				0						
		OPERATING EXPE E										
	10	Operation and Maintenance Exe e	CCCTED			0						
	11	Depreciation and Amortization Exe e	CCCTED		0	0						
		Taxes Other Than Income Taxes-General	CCCTED			0						
		Taxes Other Than Income Taxes-Distribution GRT	CCCTED			0						
		Income Taxes	CCCTED			0						
		TOTAL OPERATING EXPE E				0						
		OPERATING INCOME (RETURN)				0						
		DEVELOPMENT OF RATE BASE										
		Electric Plant in ervice	CCCTED		0	0						
	0	ess Accumulated Depreciation	CCCTED		0	0						
	1	Plus Rate Base dditions	CCCTED			0						
		ess Rate Base Deductions	CCCTED		0	0						
		TOTAL DISTRIBUTION RATE BASE	CCCTED			0						
		DISTRIBUTION RATE OF RETURN (PRESENT)										
		DISTRIBUTION INDEX RATE OF RETURN (PRESENT)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
		DEVELOPMENT OF PURCHASED POWER RETURN										
		Purchased Electric Re e	CCCTED	0		0	0	0	0	0	0	0
	0	Purchased Power O M Exe e	CCCTED	0		0	0	0	0	0	0	0
	1	Purchased Power GRT Exe e	CCCTED	0		0	0	0	0	0	0	0
		Purchased Power Income Taxes		0		0	0	0	0	0	0	0
		Purchased Power Operating Income		0		0	0	0	0	0	0	0
		Rate Base - Purchased Power Cash or ing Capita	CCCTED	0		0	0	0	0	0	0	0
		PURCHASED POWER RATE OF RETURN (PRESENT)		0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00
		DEVELOPMENT OF TRANSMISSON RETURN										
		Transmission Re e	CCCTED	0	0	0	0	0	0	0	0	0
		Transmission O M Exe e	CCCTED	0	0	0	0	0	0	0	0	0
	0	Transmission GRT Exe e	CCCTED	0	0	0	0	0	0	0	0	0
	1	Transmission Income Taxe		0	0	0	0	0	0	0	0	0
		Transmission Operating Income		0	0	0	0	0	0	0	0	0
		Rate Base - Transmission Cash or ing Capita	CCCTED	0	0	0	0	0	0	0	0	0
		TRANSMISSION RATE OF RETURN (PRESENT)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		TOTAL OPERATING INCOME (RETURN)				0						
		TOTAL RATE BASE				0						
		COMPOSITE RATE OF RETURN @ CURRENT RATES										
	0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	1	EQUALIZED RETURN AT PROPOSED ROR OF 7.98%											
		DEVELOPMENT OF DISTRIBUTION RETURN (EQUALIZED RATE)											
		RATE BASE	C□□C□□□TED					0					0
		RETURN (RATE BASE * 7.98% ROR)						0					0
		PLUS:											
		OPERATING EXPENSES											
		O□eratio□ a□d Mai□te□a□□e Ex□e□□e	C□□C□□□TED					0					0
		De□re□iatio□ a□d □□orti□atio□ Ex□e□□e	C□□C□□□TED			0		0					0
		Taxe□ Other Tha□ I□□o□e Taxe□-Ge□era□	C□□C□□□TED					0					0
	0	Taxe□ Other Tha□ I□□o□e Taxe□-Di□trib□tio□ GRT	C□□C□□□TED					0					0
	1	□tate a□d Federa□ I□□o□e Taxe□	C□□C□□□TED					0					0
		TOTAL OPERATING EXPENSES						0					0
		EQUALS TOTAL COST OF SERVICE						0					0
		LESS:											
		De□o□ i□io□g Re□e□e□	C□□C□□□TED		0		0	0	0	0	0	0	0
		Other O□erati□g Re□e□e	C□□C□□□TED			0		0					0
		EQUALS:											
		DISTRIBUTION BASE RATE SALES @ EQUALIZED ROR 7.98%						0					0
	0	Di□trib□tio□ Co□t I□□rea□e □itho□t Forfeited Di□□o□□t						0					0
	1	TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE						0					0
		REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISC						0					0
		DEVELOPMENT OF PURCH. POWER RETURN (EQUALIZED RATE)											
		RATE BASE (CWC)	C□□C□□□TED		0		0	0	0	0	0	0	0
		RETURN (RATE BASE * 7.98% ROR)			0		0	0	0	0	0	0	0
		PLUS:											
		OPERATING EXPENSES											
		P□r□ha□ed Po□er O□M Ex□e□□e	C□□C□□□TED		0		0	0	0	0	0	0	0
	0	P□r□ha□ed Po□er I□□o□e Taxe□	C□□C□□□TED		0		0	0	0	0	0	0	0
	1	P□r□ha□ed Po□er GRT Ex□e□□e	C□□C□□□TED		0		0	0	0	0	0	0	0
		EQUALS TOTAL PURCHASED POWER COST OF SERVICE			0		0	0	0	0	0	0	0
		TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE			0		0	0	0	0	0	0	0
		REVENUE INCREASE TO DISTRIBUTION REVENUES (%)		0.0□□	0.00□	0.0□□	0.00□	0.00□	0.00□	0.00□	0.00□	0.00□	0.00□
					0.00□		0.00□	0.00□	0.00□	0.00□	0.00□	0.00□	0.00□
		DEVELOPMENT OF TRANSMISSION RETURN (EQUALIZED RATE)											
		RATE BASE (CWC)	C□□C□□□TED			0	0	0		0	0	0	0
		RETURN (RATE BASE * 7.98% ROR)				0	0	0		0	0	0	0
		PLUS:											
	0	OPERATING EXPENSES											
	1	Tra□□□ i□□io□ O□M Ex□e□□e	C□□C□□□TED			0	0	0		0	0	0	0
		Tra□□□ i□□io□ I□□o□e Taxe□	C□□C□□□TED			0	0	0		0	0	0	0
		Tra□□□ i□□io□ GRT Ex□e□□e	C□□C□□□TED			0	0	0		0	0	0	0
		EQUALS TOTAL TRANSMISSION COST OF SERVICE				0	0	0		0	0	0	0
		TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE				0	0	0		0	0	0	0
		REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)		-0.0□□	-0.0□□	0.00□	0.00□	0.00□	-0.0□□	0.00□	0.00□	0.00□	0.00□
						0.00□	0.00□	0.00□		0.00□	0.00□	0.00□	0.00□
		TOTAL INCREASE (DECREASE) REQUIRED					10	0□					0□
	100												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
	1	**EQUALIZED RETURN AT PROPOSED ROR OF 7.98%**										
		DEVELOPMENT OF DISTRIBUTION RETURN (EQUALIZED RATE)										
		RATE BASE	C□□C□□□TED			0						
		RETURN (RATE BASE * 7.98% ROR)				0						
		PLUS:										
		OPERATING EXPENSES										
		O□eratio□ a□d Mai□te□a□□e Ex□e□□e	C□□C□□□TED			0						
		De□re□iatio□ a□d □□orti□atio□ Ex□e□□e	C□□C□□□TED		0	0						
		Taxe□ Other Tha□ I□□o□e Taxe□-Ge□era□	C□□C□□□TED			0						
	0	Taxe□ Other Tha□ I□□o□e Taxe□-Di□trib□tio□ GRT	C□□C□□□TED			0						
	1	□tate a□d Federa□ I□□o□e Taxe□	C□□C□□□TED			0						
		TOTAL OPERATING EXPENSES				0						
		EQUALS TOTAL COST OF SERVICE				0						
		LESS:										
		De□o□ □i□io□i□g Re□e□□e□	C□□C□□□TED	0		0	0	0	0	0	0	0
		Other O□erati□g Re□e□□e	C□□C□□□TED			0						
		EQUALS:										
		DISTRIBUTION BASE RATE SALES @ EQUALIZED ROR 7.98%				0						
	0	Di□trib□tio□ Co□t I□□rea□e □itho□t Forfeited Di□□o□□t				0						
	1	**TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE**				0						
		REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISC				0						
		DEVELOPMENT OF PURCH. POWER RETURN (EQUALIZED RATE)										
		RATE BASE (CWC)	C□□C□□□TED	0		0	0	0	0	0	0	0
		RETURN (RATE BASE * 7.98% ROR)		0		0	0	0	0	0	0	0
		PLUS:										
		OPERATING EXPENSES										
		P□r□ha□ed Po□er O□M Ex□e□□e	C□□C□□□TED	0		0	0	0	0	0	0	0
	0	P□r□ha□ed Po□er I□□o□e Taxe□	C□□C□□□TED	0		0	0	0	0	0	0	0
	1	P□r□ha□ed Po□er GRT Ex□e□□e	C□□C□□□TED	0		0	0	0	0	0	0	0
		EQUALS TOTAL PURCHASED POWER COST OF SERVICE		0		0	0	0	0	0	0	0
		TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE		0		0	0	0	0	0	0	0
		REVENUE INCREASE TO DISTRIBUTION REVENUES (%)		0.00□		0.00□	0.00□	0.00□	0.00□	0.00□	0.00□	0.00□
				0.00□		0.00□	0.00□	0.00□	0.00□	0.00□	0.00□	0.00□
		DEVELOPMENT OF TRANSMISSION RETURN (EQUALIZED RATE)										
		RATE BASE (CWC)	C□□C□□□TED	0	0	0	0	0	0	0	0	0
		RETURN (RATE BASE * 7.98% ROR)		0	0	0	0	0	0	0	0	0
		PLUS:										
	0	**OPERATING EXPENSES**										
	1	Tra□□□i□□io□ O□M Ex□e□□e	C□□C□□□TED	0	0	0	0	0	0	0	0	0
		Tra□□□i□□io□ I□□o□e Taxe□	C□□C□□□TED	0	0	0	0	0	0	0	0	0
		Tra□□□i□□io□ GRT Ex□e□□e	C□□C□□□TED	0	0	0	0	0	0	0	0	0
		EQUALS TOTAL TRANSMISSION COST OF SERVICE		0	0	0	0	0	0	0	0	0
		TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE		0	0	0	0	0	0	0	0	0
		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□	0.00□	0.00□	0.00□	0.00□	0.00□	0.00□	0.00□	0.00□
		TOTAL INCREASE (DECREASE) REQUIRED				0						
	100											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	101	**EQUALIZED RETURN AT PROPOSED ROR OF 7.98%**											
	10	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**											
	10	**RATE BASE**	C C TED		0	1	1	0	1 1	11	0	1	0
	10	**RETURN (RATE BASE * 7.98% ROR)**		0	1 0	0	1 1	0	1	1 00	1	10	0
	10	**PLUS:**											
	10	**OPERATING EXPENSES**											
	10	O eratio a d Mai te a e Ex e e	C C TED	0 11 1		1 00	1	0	1		0 1	11 1	0
	10	De re iatio a d orti atio Ex e e	C C TED			0	10	0	0		1 1		0
	10	Taxe Other Tha I o e Taxe -Ge era	C C TED		1			0	1	1	1		0
	110	Taxe Other Tha I o e Taxe -GRT	C C TED	1 01			1	0	11	0	0	1	0
	111	tate a d Federa I o e Taxe	C C TED		1	1 0 1		0			1	1	0
	11	**TOTAL OPERATING EXPENSES**			1 0 0	1 0	0	0	0 0		1	1	0
	11												
	11	**EQUALS TOTAL COST OF SERVICE**			1 0 10	1 0 1	00	0	01 1	1		0 10	0
	11	**LESS:**											
	11	De o i io i g Re e e	C C TED	1	0	1	0	0	0	0	0	0	0
	11	Other O erati g Re e e	C C TED	1		0	1	0	1				0
	11	**EQUALS:**											
	11	**OVERALL BASE RATES @ EQUALIZED ROR 7.98%**			1 1	1 0 1		0	01 0	1 1	0		0
	1 0	**COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DIS**			0	0	10	0					0
	1 1	**TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE**		0			10 0	0		1		0	0
	1												
	1												
	1												
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	1												
	1												
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
	101	**EQUALIZED RETURN AT PROPOSED ROR OF 7.98%**										
	10	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**										
	10	**RATE BASE**	C TED	00	1	0	1 1		1 1	1 0	1	1
	10	**RETURN (RATE BASE * 7.98% ROR)**		1	0	0	1	0	10 0	1	1 00	
	10	**PLUS:**										
	10	**OPERATING EXPENSES**										
	10	O eratio a d Mai te a e Ex e e	C TED	1	1 00	0	1 1 0		1	1	0 0	01
	10	De re iatio a d ortiatio Ex e e	C TED		0	0		11	0	11		1
	10	Taxe Other Tha I o e Taxe -Ge era	C TED			0		10			1	
	110	Taxe Other Tha I o e Taxe -GRT	C TED			0	0			1 1	1	00
	111	tate a d Federa I o e Taxe	C TED		1 0 1	0	0 1	1				0
	11	**TOTAL OPERATING EXPENSES**			1 0	0	1		111	1 10		0
	11											
	11	**EQUALS TOTAL COST OF SERVICE**		11 0	1 0 1	0		0	1	1 0	0	0
	11	**LESS:**										
	11	De o i io i g Re e e	C TED	0	1	0	0	0	0	0	0	0
	11	Other O erati g Re e e	C TED	11	0	0	0	1 1	1	1		
	11	**EQUALS:**										
	11	**OVERALL BASE RATES @ EQUALIZED ROR 7.98%**		110	1 0 1	0	0			11 0	1	1 1
	1 0	**COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DIS**		0	0	0		1 1		1		
	1 1	**TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE**		1		0		1		1		
	1											
	1											
	1											
	1											
	1											
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBP	1	**DEVELOPMENT OF RATE BASE**											
RBP		**ELECTRIC PLANT IN SERVICE**											
RBP		I□T□□GIB□E P□□□T											
RBP		□0□-□0□-Fra□□hi□e a□d □o□□e□t□ □ Mi□□l□ta□g□Pa	TDP□T	1□□□□□□	101□□□□	0	□□□□□□	0	0	101□□□□	□0□□□□	1□□□□□	0
RBP		□0□-	C□□TRE□	0	0	0	0	0	0	0	0	0	0
RBP		□0□-	C□□T	0	0	0	0	0	0	0	0	0	0
RBP		□0□-□MI P□a□t	CMETER□	□□□1□	0	0	□□□1□	0	0	0	0	0	0
RBP		TOT□□ I□T□□GIB□E P□□□T		1□□□□□□	101□□□□	0	□□□□□□	0	0	101□□□□	□0□□□□	1□□□□□	0
RBP													
RBP	10	TR□□□MI□□IO□ P□□□T											
RBP	11	□□0-□□□ □□□o□□t□	DTR□□	0	0	0	0	0	0	0	0	0	0
RBP	1□	□□1- Tra□□□i□□io□ Re□ated P□a□t	DTR□□	0	0	0	0	0	0	0	0	0	0
RBP	1□	TOT□□ TR□□□MI□□IO□ P□□□T		0	0	0	0	0	0	0	0	0	0
RBP	1□												
RBP	1□	DI□TRIB□TIO□ P□□□T											
RBP	1□	□□0-□a□d □ □a□d Right□	DDI□PHT	□□□1□□	□□□1□□	0	0	0	0	□□□1□□	□□□1□□	0	0
RBP	1□	□□1-□tr□□t□re□ □ I□ □ro□e□e□t□	DDI□PHT	□□□□□□□	□□□□□□□	0	0	0	0	□□□□□□□	□□□□□□□	0	0
RBP	1□	□□□-□tatio□ E□□i□□e□t	DDI□PHT	1□□0□□□□0	1□□0□□□□0	0	0	0	0	1□□0□□□□0	1□□0□□□□0	0	0
RBP	1□	□□□-Po□e□□To□er□□ Fixt□re□											
RBP	□0	Pri□ar□HT	DDI□PHT	□□0□1□□	□□0□1□□	0	0	0	0	□□0□1□□	□□0□1□□	0	0
RBP	□1	Pri□ar□	DDI□TPO□	□□□□00□	□□□□00□	0	0	0	0	□□□□00□	0	□□□□00□	0
RBP	□□	□e□o□dar□	CDI□T□O□C	□1□□□00	0	0	□1□□□00	0	0	0	0	0	0
RBP	□□	Tota□□□o□□t □□□		1□□□□□□0□	1□0□□□0□	0	□1□□□00	0	0	1□0□□□0□	□□0□1□□	□□□□00□	0
RBP	□□	□□□-O□erhead Co□d□□tor□ □ De□i□e□											
RBP	□□	Pri□ar□HT	DDI□PHT	1□101□□1□	1□101□□1□	0	0	0	0	1□101□□1□	1□101□□1□	0	0
RBP	□□	Pri□ar□	DDI□TPO□	□1□□□□□	□1□□□□□	0	0	0	0	□1□□□□□	0	□1□□□□□	0
RBP	□□	□e□o□dar□	CDI□T□□□C	□□□□0□□	0	0	□□□□0□□	0	0	0	0	0	0
RBP	□□	Tota□□□o□□t □□□		□□□□□□□0□	1□□1□□□□1	0	□□□□0□□	0	0	1□□1□□□□1	1□101□□1□	□1□□□□□	0
RBP	□□	□□□-□□dergro□□d Co□d□it											
RBP	□0	Pri□ar□HT	DDI□PHT	□□□□□□□	□□□□□□□	0	0	0	0	□□□□□□□	□□□□□□□	0	0
RBP	□1	Pri□ar□	DDI□TP□□	1□□□1□□	1□□□1□□	0	0	0	0	1□□□1□□	0	1□□□1□□	0
RBP	□□	□e□o□dar□	CDI□T□O□C	□□□□□□□	0	0	□□□□□□□	0	0	0	0	0	0
RBP	□□	Tota□□□o□□t □□□		1□0□□□□□	□□□□□□□	0	□□□□□□□	0	0	□□□□□□□	□□□□□□□	1□□□1□□	0
RBP	□□	□□□-□□dergro□□d Co□d□□tor□ □ De□i□e□											
RBP	□□	Pri□ar□HT	DDI□PHT	1□□□□□□□□	1□□□□□□□□	0	0	0	0	1□□□□□□□□	1□□□□□□□□	0	0
RBP	□□	Pri□ar□	DDI□TP□□	□□□□1□□	□□□□1□□	0	0	0	0	□□□□1□□	0	□□□□1□□	0
RBP	□□	□e□o□dar□	CDI□T□□□C	□□□□□□□0	0	0	□□□□□□□0	0	0	0	0	0	0
RBP	□□	Tota□□□o□□t □□□		□□□□□□□1□	1□□□1□□□□	0	□□□□□□□0	0	0	1□□□1□□□□	1□□□□□□□□	□□□□1□□	0
RBP	□□	□□□-i□e Tra□□for□er□	DDI□T□□T	□□0□□□□	□□0□□□□	0	0	0	0	□□0□□□□	0	0	0
RBP	□0	□□□-□er□i□e□	C□ER□ICE	□0□□□□□	0	0	□0□□□□□	0	0	0	0	0	0
RBP	□1	□□0-Meter□	CMETER□	□□□□1□0	0	0	□□□□1□0	0	0	0	0	0	0
RBP	□□	□□1-I□□ta□atio□o□C□□to□er Pre□i□e□	C□□TPREM	1□□□□□□	0	0	1□□□□□□	0	0	0	0	0	0
RBP	□□	□□□-□treet □ighti□g □ □ig□a□□□te□□	C□IGHT	□□□□□□□	0	0	□□□□□□□	0	0	0	0	0	0
RBP	□□	□□□-□□et Retire□e□t Co□t□for Di□trib□tio□P□a□t	DI□TP□TX□R	□□□□□□	1□□□□□	0	□1□	0	0	1□□□□□	1□1□□	□□□	0
RBP	□□	TOT□□ DI□TRIB□TIO□ P□□□T		10□□1□□□□□	□□□□□□1□□	0	□□□□□□□□□□	0	0	□□□□□□1□□	□□□00□1□□	1□□□□□□□□	0
RBP	□□												
RBP	□□												
RBP	□□												
RBP	□□												
RBP	□0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RBP	1	**DEVELOPMENT OF RATE BASE**										
RBP		**ELECTRIC PLANT IN SERVICE**										
RBP		I□T□□GIB□E P□□□T										
RBP		□0□-□0□-Fra□□hi□e a□d □o□□e□t□ □ Mi□□ I□ta□g□P□	TDP□T	11□□0□	0	0	□□□11□	□□□□□	□□□□□	0	0	1□1□□
RBP		□0□-	C□□TRE□	0	0	0	0	0	0	0	0	0
RBP		□0□-	C□□T	0	0	0	0	0	0	0	0	0
RBP		□0□-□MI P□□t	CMETER□	0	0	0	0	0	□□□1□	0	0	0
RBP		TOT□□ I□T□□GIB□E P□□□T		11□□0□	0	0	□□□11□	□□□□□	11□□□0	0	0	1□1□□
RBP												
RBP	10	TR□□□MI□□IO□ P□□□T										
RBP	11	□□0-□□□ □□□o□□t□	DTR□□	0	0	0	0	0	0	0	0	0
RBP	1□	□□1- Tra□□□i□□io□ Re□ated P□□t	DTR□□	0	0	0	0	0	0	0	0	0
RBP	1□	TOT□□ TR□□□MI□□IO□ P□□□T		0	0	0	0	0	0	0	0	0
RBP	1□											
RBP	1□	DI□TRIB□TIO□ P□□□T										
RBP	1□	□□0-□a□d □ □a□d Right□	DDI□PHT	0	0	0	0	0	0	0	0	0
RBP	1□	□□1-□tr□□t□re□□ I□ □ro□e□e□t□	DDI□PHT	0	0	0	0	0	0	0	0	0
RBP	1□	□□□-□tatio□ E□□i□□e□t	DDI□PHT	0	0	0	0	0	0	0	0	0
RBP	1□	□□□-Poi□□To□er□□ Fixt□re□										
RBP	□0	Pri□ar□HT	DDI□PHT	0	0	0	0	0	0	0	0	0
RBP	□1	Pri□ar□	DDI□TPO□	0	0	0	0	0	0	0	0	0
RBP	□□	□e□o□dar□	CDI□T□O□C	0	0	0	□1□□□00	0	0	0	0	0
RBP	□□	Tota□□□o□□t □□□		0	0	0	□1□□□00	0	0	0	0	0
RBP	□□	□□□-O□erhead Co□d□□tor□□ De□i□e□										
RBP	□□	Pri□ar□HT	DDI□PHT	0	0	0	0	0	0	0	0	0
RBP	□□	Pri□ar□	DDI□TPO□	0	0	0	0	0	0	0	0	0
RBP	□□	□e□o□dar□	CDI□T□□□C	0	0	0	□□□□0□□	0	0	0	0	0
RBP	□□	Tota□□□o□□t □□□		0	0	0	□□□□0□□	0	0	0	0	0
RBP	□□	□□□-□□dergro□□d Co□d□it										
RBP	□0	Pri□ar□HT	DDI□PHT	0	0	0	0	0	0	0	0	0
RBP	□1	Pri□ar□	DDI□TP□□	0	0	0	0	0	0	0	0	0
RBP	□□	□e□o□dar□	CDI□T□O□C	0	0	0	□□□□□□0	0	0	0	0	0
RBP	□□	Tota□□□o□□t □□□		0	0	0	□□□□□□0	0	0	0	0	0
RBP	□□	□□□-□□dergro□□d Co□d□□tor□□ De□i□e□										
RBP	□□	Pri□ar□HT	DDI□PHT	0	0	0	0	0	0	0	0	0
RBP	□□	Pri□ar□	DDI□TP□□	0	0	0	0	0	0	0	0	0
RBP	□□	□e□o□dar□	CDI□T□□□C	0	0	0	□□□□□□0	0	0	0	0	0
RBP	□□	Tota□□□o□□t □□□		0	0	0	□□□□□□0	0	0	0	0	0
RBP	□□	□□□-□i□e Tra□□for□er□	DDI□T□□T	□□0□□□□	0	0	0	0	0	0	0	0
RBP	□0	□□□-□er□i□e□	C□ER□ICE	0	0	0	0	□0□□□□□	0	0	0	0
RBP	□1	□□0-Meter□	CMETER□	0	0	0	0	0	□□□□1□0	0	0	0
RBP	□□	□□1-I□□ta□atio□ o□ C□□to□er Pre□i□e□	C□□TPREM	0	0	0	0	0	0	0	0	1□□□□□
RBP	□□	□□□-□treet □ighti□g □ □ig□a□□□te□□	C□IGHT	0	0	0	0	0	0	0	0	□□□□□□
RBP	□□	□□□-□□□et Retire□e□t Co□t□for Di□trib□tio□ P□□t	DI□TP□TX□R	□0□	0	0	□10	110	□0	0	0	□0
RBP	□□	TOT□□ DI□TRIB□TIO□ P□□□T		□□0□□□□	0	0	1□□□□□□11	□0□□□□□	□□□□□□0	0	0	□0□□□□
RBP	□□											
RBP	□□											
RBP	□□											
RBP	□□											
RBP	□0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBP	1	**ELECTRIC PLANT IN SERVICE CONTINUED**											
RBP													
RBP		GE ER P T											
RBP		-a d a d a d Right				0		0	0			11	0
RBP		0-tr t re a d l ro e e t		0	1 0	0	0	0	0	1 0	1 1		0
RBP		1-Offi e F r it re E i e t		1	0	0		0	0	0		0	0
RBP		-tore E i e t			1	0	1	0	0	1	1		0
RBP		-Too ho Garage E i			1	0		0	0	1	1 1	10	0
RBP		-aborator E i e t		1		0		0	0			1	0
RBP	0	-Co i atio E i e t		1	1	0		0	0	1		0 0	0
RBP	1	-Mi e a eo E i e t RO			11	0	1	0	0	11			0
RBP		-Other Ta gib e Pro ert		1		0		0	0		0	0	0
RBP		TOT GE ER P T		0	1 0 0	0	1 1	0	0	1 0 0	101	10	0
RBP													
RBP													
RBP		**TOTAL ELECTRIC PLANT IN SERVICE**		11 0	10 1	0	0	0	0	10 1		1 1 1	0
RBP													
RBP													
RBP													
RBP	0												
RBP	1												
RBP													
RBP													
RBP													
RBP													
RBP													
RBP													
RBP													
RBP													
RBP													
RBP													
RBP													
RBP	0												
RBP	1												
RBP													
RBP													
RBP													
RBP													
RBP													
RBP													
RBP													
RBP													
RBP	100												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RBP	1	**ELECTRIC PLANT IN SERVICE CONTINUED**										
RBP												
RBP		GE ER P T										
RBP		-a d a d Right	GE	11	0	0	1		1		1	
RBP		0-tr t re a d l ro e e t	GE		0	0		0		1 0		11
RBP		1-Offi e F r it re E i e t	GE		0	0				11		
RBP		-tore E i e t	GE	0	0	0		0	1	10	1	
RBP		-Too ho Garage E i	GE		0	0	1		1 10	1 0	0	
RBP		-aborator E i e t	GE		0	0	1	1				
RBP	0	-Co i atio E i e t	GE	1	0	0	0				0	
RBP	1	-Mi e a eo E i e t RO	GE		0	0	0		1	1		0
RBP		-Other Ta gib e Pro ert	GE	0	0	0						0
RBP		TOT GE ER P T		0	0	0	0	1 01		1		1
RBP												
RBP												
RBP		**TOTAL ELECTRIC PLANT IN SERVICE**			0	0	1	11	1	1		10
RBP												
RBP												
RBP												
RBP	0											
RBP	1											
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP	0											
RBP	1											
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP	0											
RBP	1											
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP												
RBP	100											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBD	1	**LESS: ACCUMULATED DEPRECIATION**											
RBD													
RBD		I□T□□GIB□E P□□□T □CC□M□□□TED DEPRECI□TIO I□TP□T		□□□□□□	□□□1□□	0	1□□□□□	0	0	□□□1□□	□□□00□	□□□□□	0
RBD													
RBD		TR□□□MI□□IO□ P□□□T □CC□M□□□TED DEPRECI□ TR□□P□T		0	0	0	0	0	0	0	0	0	0
RBD													
RBD		DI□TRIB□TIO□ P□□□T □CC□M□□□TED DEPRECI□TIO□											
RBD		□□0-□a□d □ □a□d Right□	P□T□□□0	□10	□10	0	0	0	0	□10	□10	0	0
RBD		□□1-□tr□□t□re□□ I□ □ro□e□e□t□	P□T□□□1	□□□□□□	□□□□□□	0	0	0	0	□□□□□□	□□□□□□	0	0
RBD	10	□□□-□tatio□ E□□i□□e□t	P□T□□□□	□□□□□□1	□□□□□□1	0	0	0	0	□□□□□□1	□□□□□□1	0	0
RBD	11	□□□-Po□e□To□er□□ Fixt□re□	P□T□□□□	□□□0□□	□□□□1□	0	□□□□□□	0	0	□□□□1□	□□□□□0	□1□□□□	0
RBD	1□	□□□-O□erhead Co□d□□tor□□ De□i□e□	P□T□□□□	□1□□□0	□□□□□□	0	□□□□□□	0	0	□□□□□□	1□□□0□□	□1□□□□	0
RBD	1□	□□□-□□dergro□□d Co□d□it	P□T□□□□	1□□□1□□	1□0□□□	0	□□□1□□	0	0	1□0□□□	11□□1□□	□1□□□□	0
RBD	1□	□□□-□□dergro□□d Co□d□□tor□□ De□i□e□	P□T□□□□	□0□□□□	1□□□□0	0	□□□□□□	0	0	1□□□□0	1□□□□□	□□□0□□	0
RBD	1□	□□□-□i□e Tra□□for□er□	P□T□□□□	1□□□□0□	1□□□□0□	0	0	0	0	1□□□□0□	0	0	0
RBD	1□	□□□-□er□i□e□	P□T□□□□	□1□□0□□	0	0	□1□□0□□	0	0	0	0	0	0
RBD	1□	□□0-Meter□	P□T□□□0	□□□□□□□	0	0	□□□□□□□	0	0	0	0	0	0
RBD	1□	□□1-I□□ta□atio□o□ C□□to□er Pre□i□e□	P□T□□□1	11□□□□	0	0	11□□□□	0	0	0	0	0	0
RBD	1□	□□□-□treet □ighti□g □ □ig□a□□□te□□	P□T□□□□	□□□1□□	0	0	□□□1□□	0	0	0	0	0	0
RBD	□0	□□□-□□□et Retire□e□t Co□t□for Di□trib□tio□P□a□t	DI□TP□TX□R	1□□0□	1□□0□	0	□0□	0	0	1□□0□	□□0	□□1	0
RBD	□1	TOT□□ DI□TRIB□TIO□ P□□□T □CC□M□□□TED DEPRECI□TIO□		□0□□□□□□	1□□□□□□□0	0	□0□□□□□	0	0	1□□□□□□□0	1□01□□1□□	1□□□□□□	0
RBD	□□												
RBD	□□	GE□ER□□ P□□□T □CC□M□□□TED DEPRECI□TIO□ GE□□P□T		1□□□1□1	□□□11□	0	□□□01□	0	0	□□□11□	□□□□□□	1□□□□□	0
RBD	□□												
RBD	□□	**TOTAL ACCUMULATED DEPRECIATION**		□□□□□□□□	1□□□□□□□□	0	□□□□□□□	0	0	1□□□□□□□□	1□0□□□□1□	1□1□1□□	0
RBD	□□												
RBD	□□												
RBD	□□												
RBD	□□	**NET ELECTRIC PLANT IN SERVICE**		□□□□□□1□□	□□□□□□□□□	0	□□□□□□□□□	0	0	□□□□□□□□□	□□□□□□□□0	1□□00□□□□	0
RBD	□0												
RBD	□1												
RBD	□□												
RBD	□□												
RBD	□□												
RBD	□□												
RBD	□□												
RBD	□□												
RBD	□□												
RBD	□□												
RBD	□0												
RBD	□1												
RBD	□□												
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RBD	□□												
RBD	□0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RBD	1	**LESS: ACCUMULATED DEPRECIATION**										
RBD												
RBD		I□T□□GIB□E P□□□T □CC□M□□□TED DEPRECI□TIO I□TP□T		□□□□□	0	0	□□□□1	□□□□□	□□□□□	0	0	□□□
RBD												
RBD		TR□□□MI□□IO□ P□□□T □CC□M□□□TED DEPRECI□ TR□□P□T		0	0	0	0	0	0	0	0	0
RBD												
RBD		DI□TRIB□TIO□ P□□□T □CC□M□□□TED DEPRECI□TIO□										
RBD		□□0-□a□d □ □a□d Right□	P□T□□□0	0	0	0	0	0	0	0	0	0
RBD		□□1-□tr□□t□re□□ I□ □ro□e□e□t□	P□T□□□1	0	0	0	0	0	0	0	0	0
RBD	10	□□□-□tatio□ E□□i□□e□t	P□T□□□□	0	0	0	0	0	0	0	0	0
RBD	11	□□□-Po□e□To□er□□ Fixt□re□	P□T□□□□	0	0	0	□□□□□□	0	0	0	0	0
RBD	1□	□□□-O□erhead Co□d□□tor□□ De□i□e□	P□T□□□□	0	0	0	□□□□□□	0	0	0	0	0
RBD	1□	□□□-□□dergro□□d Co□d□it	P□T□□□□	0	0	0	□□□1□□	0	0	0	0	0
RBD	1□	□□□-□□dergro□□d Co□d□□tor□□ De□i□e□	P□T□□□□	0	0	0	□□□□□□	0	0	0	0	0
RBD	1□	□□□-□i□e Tra□□for□er□	P□T□□□□	1□□□0□	0	0	0	0	0	0	0	0
RBD	1□	□□□-□er□i□e□	P□T□□□□	0	0	0	0	□1□0□□	0	0	0	0
RBD	1□	□□0-Meter□	P□T□□□0	0	0	0	0	0	□□□□□□	0	0	0
RBD	1□	□□1-I□□ta□atio□ o□ C□□to□er Pre□i□e□	P□T□□□1	0	0	0	0	0	0	0	0	11□□□
RBD	1□	□□□-□treet □ighti□g □ □ig□a□□□te□ □	P□T□□□□	0	0	0	0	0	0	0	0	□□□1□□
RBD	□0	□□□-□□□et Retire□e□t Co□t□for Di□trib□tio□ P□a□t	DI□TP□TX□R	1□□	0	0	□□□	□□	□□	0	0	1□
RBD	□1	TOT□□ DI□TRIB□TIO□ P□□□T □CC□M□□□TED DEPRECI□TIO□		1□□□□□□	0	0	□0□□□01	□1□□1□□	□□□□□□□	0	0	□□□□□□
RBD	□□											
RBD	□□	GE□ER□□ P□□□T □CC□M□□□TED DEPRECI□TIO□ GE□□P□T		1□□□□	0	0	1□□□01	□□□□	□□□□□	□□□□□□	1□□□□	□□11□
RBD	□□											
RBD	□□	**TOTAL ACCUMULATED DEPRECIATION**		1□□□□□□	0	0	□□□□□□□	□1□□□□□	□□□□□□□	□□□□□□	1□□□□	□□□□□□
RBD	□□											
RBD	□□											
RBD	□□											
RBD	□□	**NET ELECTRIC PLANT IN SERVICE**		□□□□□□1	0	0	1□□1□□□□	□□□□1□□	1□□□□□□	□1□□□□	□□□1□	□0□□□□
RBD	□0											
RBD	□1											
RBD	□□											
RBD	□□											
RBD	□□											
RBD	□□											
RBD	□□											
RBD	□□											
RBD	□□											
RBD	□□											
RBD	□0											
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RBD	□□											
RBD	□□											
RBD	□□											
RBD	□0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**											
RBO													
RBO		**PLUS: ADDITIONS TO RATE BASE**											
RBO													
RBO		COMMO P T	GE			0		0	0				0
RBO													
RBO		**WORKING CAPITAL**											
RBO		P rha ed Po er Ca h or g Ca ita	C C TED	1	0	1	0	0	0	0	0	0	0
RBO		Tra i tio Ca h or g Ca ita	C C TED	1	1	0	0	0	1	0	0	0	0
RBO	10	Di trib tio											
RBO	11	Ca h or g Ca ita	C C TED	1	101 0	1		0	01	1		0 1	0
RBO	1	Materia a d ie	TOTP T	0	1	0	1	0	0	1	1 1		0
RBO	1	Tota Di trib tio or g Ca ita		1 0 0	1 0	1		0	01	11 0	0	1	0
RBO	1	TOT OR I G C PIT		1	1	1		0	1 1	11 0	0	1	0
RBO	1	TOT DDITIO TO R TE B E		01 1	0 1	1		0	1 1	1	1		0
RBO	1												
RBO	1	**LESS: DEDUCTIONS TO RATE BASE**											
RBO	1	C to er De o it	C TDEP	1	0	0	1	0	0	0	0	0	0
RBO	1	C to er d a e for Co tr tio	C T D	1	1	0		0	0	1	1 1	1	0
RBO	0	Deferred I o e Taxe a d Credit											
RBO	1	P a t	TOTP T	1	01 0	0	1	0	0	01 0		1	0
RBO		Co o P a t	GE		0	0		0	0	0			0
RBO		Cor orate ter ati e Mi i Tax	TOTP T	1 0	1	0	1	0	0	1	1	1	0
RBO		a orti ed MR I e t e t	CMETER	0	0	0	0	0	0	0	0	0	0
RBO		Co trib tio i id of Co tr tio CI C	C T D	1	0 1	0		0	0	01	1	00	0
RBO		Tota Deferred I o e Taxe a d Credit		1	1	0	1	0	0	1	0 1	1 0	0
RBO		TOT DED CTIO TO R TE B E				0	11	0	0		1 1	1 1 0	0
RBO													
RBO													
RBO	0	Tota Di trib tio dditio to Rate Ba e		0		1		0	01	1	1		0
RBO	1												
RBO		TOT P RCH ED PO ER R TE B E		1	0	1	0	0	0	0	0	0	0
RBO		TOT TR M IO R TE B E		1	1	0	0	0	1	0	0	0	0
RBO		TOT DI TRIB TIO R TE B E		00	1 1	1	1	0	01	11	0	1	0
RBO													
RBO		**TOTAL RATE BASE**			0	1	1	0	1 1	11	0	1	0
RBO													
RBO													
RBO													
RBO	0												
RBO	1												
RBO													
RBO													
RBO													
RBO													
RBO													
RBO													
RBO													
RBO	0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**										
RBO												
RBO		**PLUS: ADDITIONS TO RATE BASE**										
RBO												
RBO		COMMO P T	GE	0	0	0	0					
RBO												
RBO		**WORKING CAPITAL**										
RBO		P r ha ed Po er Ca h or i g Ca ita	C C TED	0	1	0	0	0	0	0	0	0
RBO		Tra i io Ca h or i g Ca ita	C C TED	0	0	0	0	0	0	0	0	0
RBO	10	Di trib tio										
RBO	11	Ca h or i g Ca ita	C C TED	11	1	0	0	1				
RBO	1	Materia a d ie	TOTP T		0	0	1	1	1	0	1	
RBO	1	Tota Di trib tio or i g Ca ita			1	0	0	0	1	1		0
RBO	1	TOT OR I G C PIT			1	0	0	0	1	1		0
RBO	1	TOT DDITIO TO R TE B E		1	1	0	10		1	1	11	0
RBO	1											
RBO	1	**LESS: DEDUCTIONS TO RATE BASE**										
RBO	1	C to er De o it	C TDEP	0	0	0	0	0	0	0	0	1
RBO	1	C to er d a e for Co tr tio	C T D	0	0	0		0	0	0	0	0
RBO	0	Deferred I o e Taxe a d Credit										
RBO	1	P a t	TOTP T	0	0	0	1					
RBO		Co o P a t	GE	1	0	0	10	1	1	1	1	
RBO		Cor orate ter ati e Mi i Tax	TOTP T	10	0	0						1
RBO		a orti ed MR I e t e t	CMETER	0	0	0	0	0	0	0	0	0
RBO		Co trib tio i id of Co tr tio CI C	C T D	0	0	0		0	0	0	0	0
RBO		Tota Deferred I o e Taxe a d Credit		0	0	0	1	0	0	00	1	11
RBO		TOT DED CTIO TO R TE B E		0	0	0	1	0	0	00	1	
RBO												
RBO												
RBO	0	Tota Di trib tio dditio to Rate Ba e		1	1	0	10		1	1	11	0
RBO	1											
RBO		TOT P RCH ED PO ER R TE B E		0	1	0	0	0	0	0	0	0
RBO		TOT TR M IO R TE B E		0	0	0	0	0	0	0	0	0
RBO		TOT DI TRIB TIO R TE B E		00	1	0	1		1	1	1	1
RBO												
RBO		**TOTAL RATE BASE**		00	1	0	1		1	1	1	1
RBO												
RBO												
RBO												
RBO	0											
RBO	1											
RBO												
RBO												
RBO												
RBO												
RBO												
RBO												
RBO												
RBO												
RBO	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	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**											
RBC		**DISTRIBUTION**											
RBC		O□M EXPE□□E RE□□TED C□□H □ OR□I□G C□PIT□□											
RBC		Pa□ro□□Di□trib□tio□ O□□□	□□□□ □GE□	1□□□□□□	□□□□□□	0	□□□□□□	0	0	□□□□□□	□□□□□□	□1□□□□	0
RBC		Pe□□io□	□□□□ □GE□	□□□1□	1□□□□	0	1□□1□	0	0	1□□□□	1□1□□	□□□	0
RBC		Other Ex□e□□e□	OMXPPPP	□□□□□□□	□□□□□□□	□□□□□	□□□□1□0	0	1□0□□□□	□□□□□□□	1□□□□1□	□□□□□□	0
RBC		TOT□□ EXPE□□E□		□□□□□1□	□□□□□□□	□□□□□	□□□□1□□	0	1□0□□□□	□□□1□□□	□□0□□□□	□□□□□□	0
RBC		POR □ or□□g Ca□ita□	POR	1□0□□□□0□	□□□□□□0	□□0□□	□□□0□□	0	□□0	□□□□□□0	□1□□□□	1□□□□□1	0
RBC		TOT□□ EXPE□□E□ PER D□□		□□□□□	□□□□□	□□	1□□□□	0	□□□	□□1□□	□□□□□	□□0	0
RBC	10												
RBC	11	C□ C RE□ □IREME□T □TOT□□ EXPE□□E□ x EXPE□□E □□G□		□1□□1□	□□□□□□	□□□	□□□□□□	0	□□□0□	□□□□1□	□1□0□□	10□□□□	0
RBC	1□												
RBC	1□	□□ER□GE PREP□□ME□T□		□□□□□	□□□□□	1□1□□	□□□□□	0	□□□	□□□□□	□□□□1	□□□	0
RBC	1□	DI□TRIB□TIO□ □CCR□ED T□XE□		□0□0□□	□□□□□□	□□□	□□□□□□	0	□0	□□□□□□	□□□□□□	11□1□□	0
RBC	1□	I□TERE□T P□□ME□T□	TOTP□T	□□0□□□1□	□1□□□□1□	0	□□□□□0□	0	0	□1□□□□1□	□10□□□□□	□□□□□1□	0
RBC	1□												
RBC	1□												
RBC	1□	□ET DI□TRIB□TIO□ C□□H □ OR□I□G C□PIT□□ RE□ □IREME□T		1□□□□□□	101□0□□	□□1□□	□□□□□□	0	□□□01	□□□1□□	□□□□□□	□0□1□□	0
RBC	1□												
RBC	□0												
RBC	□1	**PURCHASED POWER**											
RBC	□□	O□M EXPE□□E RE□□TED C□□H □ OR□I□G C□PIT□□											
RBC	□□	Co□ □odit□P□r□ha□ed - Co□tra□t P□r□ha□e□	E□ERG□1	□□□□□□□	0	□□□□□□□	0	0	0	0	0	0	0
RBC	□□	Co□ □odit□P□r□ha□ed - □□ot Mar□et P□r□ha□e□	E□ERG□1	□□1□0	0	□□1□0	0	0	0	0	0	0	0
RBC	□□	TOT□□ EXPE□□E□		1□00□□□1□	0	1□00□□□1□	0	0	0	0	0	0	0
RBC	□□												
RBC	□□	TOT□□ EXPE□□E□ PER D□□		□□□□0	0	□□□□0	0	0	0	0	0	0	0
RBC	□□												
RBC	□□	PP C□ C RE□ □IREME□T □TOT□□ EXPE□□E□ x EXPE□□E □□G□		□□□1□□	0	□□□1□□	0	0	0	0	0	0	0
RBC	□0												
RBC	□1	E□erg□ □CCR□ED T□XE□	E□ERG□1	0	0	0	0	0	0	0	0	0	0
RBC	□□												
RBC	□□	□ET E□erg□C□□H □ OR□I□G C□PIT□□ RE□ □IREME□T		□□□1□□	0	□□□1□□	0	0	0	0	0	0	0
RBC	□□												
RBC	□□	**TRANSMISSION**											
RBC	□□	O□M EXPE□□E - PJM Tra□□□i□□io□P□r□ha□e	DTR□□	□1□□□□	□1□□□□	0	0	0	□1□□□□	0	0	0	0
RBC	□□												
RBC	□□	TOT□□ EXPE□□E□ PER D□□		□□1	□□1	0	0	0	□□1	0	0	0	0
RBC	□□												
RBC	□0	C□ C RE□ □IREME□T □TOT□□ EXPE□□E□ x EXPE□□E □□G□		□□□1□	□□□1□	0	0	0	□□□1□	0	0	0	0
RBC	□1												
RBC	□□	TR□□□MI□□IO□ □CCR□ED T□XE□	DTR□□	0	0	0	0	0	0	0	0	0	0
RBC	□□												
RBC	□□	□ET TR□□□MI□□IO□ C□□H □ OR□I□G C□PIT□□ RE□ □IREME□T		□□□1□	□□□1□	0	0	0	□□□1□	0	0	0	0
RBC	□□												
RBC	□□												
RBC	□□	□ET TOT□□ C□□H □ OR□I□G C□PIT□□ RE□ □IREME□T		□1□□□□□	110□□□□	□□□□□1	□□□□□□	0	1□□□1□	□□□1□□	□□□□□□	□0□1□□	0
RBC	□□												
RBC	□□												
RBC	□0												

PECO Energy Company
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For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**										
RBC		**DISTRIBUTION**										
RBC		O□M EXPE□□E RE□□TED C□□H □ OR□I□G C□PIT□□										
RBC		Pa□ro□□Di□trib□tio□ O□□□	□□□□ □GE□		0	0						
RBC		Pe□□io□	□□□□ □GE□		0	0						
RBC		Other Ex□e□□e□	OMXPPPP			0						
RBC		TOT□□ EXPE□□E□				0						
RBC		POR □ or□i□g Ca□ita□	POR			0						
RBC		TOT□□ EXPE□□E□ PER D□□				0						
RBC	10											
RBC	11	C□ C RE□ □IREME□T □TOT□□ EXPE□□E□ x EXPE□□E □□G□				0						
RBC	1□											
RBC	1□	□□ER□GE PREP□□ME□T□				0						
RBC	1□	DI□TRIB□TIO□ □CCR□ED T□XE□				0						
RBC	1□	I□TERE□T P□□ME□T□	TOTP□T		0	0						
RBC	1□											
RBC	1□											
RBC	1□	□ET DI□TRIB□TIO□ C□□H □ OR□I□G C□PIT□□ RE□ □IREME□T				0						
RBC	1□											
RBC	□0											
RBC	□1	**PURCHASED POWER**										
RBC	□□	O□M EXPE□□E RE□□TED C□□H □ OR□I□G C□PIT□□										
RBC	□□	Co□ □odit□P□r□ha□ed - Co□tra□t P□r□ha□e□	E□ERG□1	0		0	0	0	0	0	0	0
RBC	□□	Co□ □odit□P□r□ha□ed - □□ot Mar□et P□r□ha□e□	E□ERG□1	0		0	0	0	0	0	0	0
RBC	□□	TOT□□ EXPE□□E□		0		0	0	0	0	0	0	0
RBC	□□											
RBC	□□	TOT□□ EXPE□□E□ PER D□□		0		0	0	0	0	0	0	0
RBC	□□											
RBC	□□	PP C□ C RE□ □IREME□T □TOT□□ EXPE□□E□ x EXPE□□E □□G□		0		0	0	0	0	0	0	0
RBC	□0											
RBC	□1	E□erg□ □CCR□ED T□XE□	E□ERG□1	0	0	0	0	0	0	0	0	0
RBC	□□											
RBC	□□	□ET E□erg□C□□H □ OR□I□G C□PIT□□ RE□ □IREME□T		0		0	0	0	0	0	0	0
RBC	□□											
RBC	□□	**TRANSMISSION**										
RBC	□□	O□M EXPE□□E - PJM Tra□□□i□□io□ P□r□ha□e	DTR□□	0	0	0	0	0	0	0	0	0
RBC	□□											
RBC	□□	TOT□□ EXPE□□E□ PER D□□		0	0	0	0	0	0	0	0	0
RBC	□□											
RBC	□0	C□ C RE□ □IREME□T □TOT□□ EXPE□□E□ x EXPE□□E □□G□		0	0	0	0	0	0	0	0	0
RBC	□1											
RBC	□□	TR□□□MI□□IO□ □CCR□ED T□XE□	DTR□□	0	0	0	0	0	0	0	0	0
RBC	□□											
RBC	□□	□ET TR□□□MI□□IO□ C□□H □ OR□I□G C□PIT□□ RE□ □IREME□T		0	0	0	0	0	0	0	0	0
RBC	□□											
RBC	□□											
RBC	□□	□ET TOT□□ C□□H □ OR□I□G C□PIT□□ RE□ □IREME□T				0						
RBC	□□											
RBC	□□											
RBC	□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	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**											
RBC													
RBC		**LAG/LEAD DAYS**		**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**
RBC		RE□E□□E □□G D□□□	□1□□□										
RBC		EXPE□□E □□G D□□□	□□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□
RBC		P□RCH□□ED PO□ ER RE□E□□E □□G D□□□	□1□□□										
RBC		P□RCH□□ED PO□ ER EXP □□G D□□□	□□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□
RBC		TR□□□MI□□IO□ RE□E□□E □□G D□□□	□1□□□										
RBC		TR□□□MI□□IO□ EXP □□G D□□□	1□□□0	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□
RBC	10	DI□TRIB□TIO□ RE□E□□E □□G D□□□	□1□□□										
RBC	11	DI□TRIB□TIO□ □□G D□□□	□□□□□	1□□1□	1□□1□	1□□1□	1□□1□	1□□1□	1□□1□	1□□1□	1□□1□	1□□1□	1□□1□
RBC	1□												
RBC	1□												
RBC	1□												
RBC	1□												
RBC	1□	DI□TRIB□TIO□ □CCR□ED T□XE□											
RBC	1□	Federa□ □□o□e Tax	EBT	1□□11□1 □□	1□10 □□□□□	□0□	□0 □□□□□	0	□□□1□	1□10 □□□□□	□□1 □□□1	□□□□□□□	0
RBC	1□	□tate I□□o□e Tax	EBT	□□1 □□□□	1 □□□□□	10□	□□□01□	0	□□□□	1 □□□□0□	1□1 □□□□	□□□□0□	0
RBC	1□	P□RT□ Taxe□	P□T□□□01	□□□□□□0	□□□□□□0	0	0	0	0	□□□□□□0	□□□□□□0	0	0
RBC	□0	Ca□ita□□to□□	C□P□TOC□	0	0	0	0	0	0	0	0	0	0
RBC	□1	P□ □ □o□a□□e Taxe□	C□□IMRE□	0	0	0	0	0	0	0	0	0	0
RBC	□□	P□ Pro□ert□tax	TOTP□T	□□□□□□□	□□□□□0□	0	□□□1□0	0	0	□□□□□0□	1 □□□□□1	□1 □□1□	0
RBC	□□	P□ Cor□ □oa□ Tax	TOTP□T	0	0	0	0	0	0	0	0	0	0
RBC	□□	Phi□ade□hia BPT	□□□E□RE□	0	0	0	0	0	0	0	0	0	0
RBC	□□	□o□a□Pri□ege Tax	□□□E□RE□	0	0	0	0	0	0	0	0	0	0
RBC	□□	Gro□□Re□ei□t□Tax	□□□E□RE□	□□□□□□□□1	1 □□□□□□□□	1□0 □□□□	10 □□□0 □□□□	0	□□□0 □□	1 □□□00 1□0	10 □□□□□□□	□□□□□□□□	0
RBC	□□	□ag Da□□ eighted □□r□ed Taxe□		□□□□1□□1 □□	1 □□1 □□□□□1	1□1 □□□□	10 □□□□1 □□	0	□□□□□□	1□0 □□□□0□	1 □□□1 □□□□	□0 □□□10□	0
RBC	□□	Tota□□□r□ed Taxe□C□ C		□0□0□□	□□□□□□	□□□□	□□□□□□	0	□0	□□□□□□	□□□□□□	11□1 □□	0
RBC	□□												
RBC	□0	DI□TRIB□TIO□ □□ER□GE PREP□□ME□T□											
RBC	□1	C□□to□er Ex□erie□□e	C□□T	1□□	0	0	1□□	0	0	0	0	0	0
RBC	□□	EEI□E□P a□d EPRI D□e□	C□□IMRE□	□□□	1□□	1□□	□□	0	□□	1□□	11□	□□	0
RBC	□□	P□C □□e□□- E□ë□tri□	C□□IMRE□	□□□□□	1 □□□□	1□0 □□	□11	0	1□□	1□□□□	□□□	□□□	0
RBC	□□	Pre□aid Re□t□a□d Po□e □tta□h□e□t Fee□	P□T□□□□	□□□	□□□	0	1□□	0	0	□□□	□10	11□	0
RBC	□□	□a□d □ea□i□g	DI□TP□T	□0	□1	0	1□	0	0	□1	□□	10	0
RBC	□□	E□□i□□e□t Mai□te□a□□e	DI□TP□T	1□□	10□	0	□□	0	0	10□	□1	□0	0
RBC	□□	B□□i□e□□ □□□□ort □□□te□	C□□T	□0□	0	0	□0□	0	0	0	0	0	0
RBC	□□	□EB□ □d□□t□e□t	□□□□ □GE□	□□□□1	1□1 □□	0	1□1 □□	0	0	1□1 □□	□1□	□□□	0
RBC	□□	Fa□i□tie□Co□tra□t□	DI□TP□T	□□	□□	0	10	0	0	□□	1□	□	0
RBC	□0	IT □er□i□e Co□tra□t□	TOTP□T	□□□	□□1	0	1□□	0	0	□□1	□□0	□□	0
RBC	□1	F□eet □□ti□tie□	GE□□P□T	□□1	1□□	0	1□□	0	0	1□□	10□	□□	0
RBC	□□	Po□tage	C□□TBI□□□	□□□	0	0	□□□	0	0	0	0	0	0
RBC	□□	TOT□□ □□ER□GE PREP□□ME□T□		□□□□□	□□□□□	1□1 □□	□□□□□	0	□□□	□□□□□	□□□□1	□□□	0
RBC	□□												
RBC	□□												
RBC	□□												
RBC	□□												
RBC	□□												
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RBC	□0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**										
RBC												
RBC		**LAG/LEAD DAYS**		**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**
RBC		RE□E□□E □□G D□□□	□1□□□									
RBC		EXPE□□E □□G D□□□	□□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□
RBC		P□RCH□□ED PO□ ER RE□E□□E □□G D□□□	□1□□□									
RBC		P□RCH□□ED PO□ ER EXP □□G D□□□	□□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□	1□□□□
RBC		TR□□□MI□□IO□ RE□E□□E □□G D□□□	□1□□□									
RBC		TR□□□MI□□IO□ EXP □□G D□□□	1□□□0	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□
RBC	10	DI□TRIB□TIO□ RE□E□□E □□G D□□□	□1□□□									
RBC	11	DI□TRIB□TIO□ □□G D□□□	□□□□□	1□□1□	1□□1□	1□□1□	1□□1□	1□□1□	1□□1□	1□□1□	1□□1□	1□□1□
RBC	1□											
RBC	1□											
RBC	1□											
RBC	1□											
RBC	1□	DI□TRIB□TIO□ □CCR□ED T□XE□										
RBC	1□	Federa□I□□o□e Tax	EBT	1□□□□□□	□0□	0	□□□□□□□	□□□□□□	11□□□□	□□□□□□	□□□□□	□□□0□
RBC	1□	□tate I□□o□e Tax	EBT	□0□□□□	10□	0	□□□□1□	□□□0□	1□□□□	□□□0□	□1□	□□□
RBC	1□	P□RT□ Taxe□	P□T□□□01	0	0	0	0	0	0	0	0	0
RBC	□0	Ca□ita□□to□□	C□P□TOC□	0	0	0	0	0	0	0	0	0
RBC	□1	P□ □ □o□a□□□e Taxe□	C□□IMRE□	0	0	0	0	0	0	0	0	0
RBC	□□	P□ Pro□ert□tax	TOTP□T	□0□□0□	0	0	□□□0□□	1□□□□1	1□□□□1	□□□□□	1□□	□□□□0
RBC	□□	P□ Cor□ □oa□ Tax	TOTP□T	0	0	0	0	0	0	0	0	0
RBC	□□	Phi□ade□hia BPT	□□□E□RE□	0	0	0	0	0	0	0	0	0
RBC	□□	□o□a□Pri□i□ege Tax	□□□E□RE□	0	0	0	0	0	0	0	0	0
RBC	□□	Gro□□Re□ei□t□Tax	□□□E□RE□	1□□□□□□□	1□0□□□□	0	□□□□□□11	□□1□□□0	□1□□□□□	□□□□□□□	□□□□□□	□□□□□□0
RBC	□□	□ag Da□□ eighted □□r□ed Taxe□		1□□00□□□	1□1□□□□	0	□□10□□0□□	□□□□□□1	□□□□□□□	□□□1□□□□	□□□□□□	□□1□□1□
RBC	□□	Tota□□□r□ed Taxe□C□ C		□□□□□	□□□□	0	1□□□□□	1□□□□	□□□1□	□□□□□	1□□□□	1□□□□
RBC	□□											
RBC	□0	DI□TRIB□TIO□ □□ER□GE PREP□□ME□T□										
RBC	□1	C□□to□er Ex□erie□□e	C□□T	0	0	0	0	0	0	0	0	1□□
RBC	□□	EEI□E□P a□d EPRI D□e□	C□□IMRE□	1□	1□□	0	□□	□	□	□□	□	□
RBC	□□	P□C □□□e□□- E□e□tri□	C□□IMRE□	10□	1□0□□	0	□□□	□□	□□	□0□	□□	□1
RBC	□□	Pre□aid Re□t□a□d Po□e □tta□h□e□t Fee□	P□T□□□□	0	0	0	1□□	0	0	0	0	0
RBC	□□	□a□d □ea□i□g	DI□TP□T	□	0	0	1□	□	□	0	0	1
RBC	□□	E□□i□□e□t Mai□te□a□□e	DI□TP□T	1□	0	0	□□	□	□	0	0	1
RBC	□□	B□□i□e□□ □□□□ort □□□te□	C□□T	0	0	0	0	0	0	0	0	□0□
RBC	□□	□EB□ □d□□t□e□t	□□□□ □GE□	□□	0	0	□□□	10	□0	□11	□□	10□
RBC	□□	Fa□i□tie□Co□tra□t□	DI□TP□T	□	0	0	□	□	1	0	0	0
RBC	□0	IT □er□i□e Co□tra□t□	TOTP□T	□□	0	0	□□	□□	1□	□	0	□
RBC	□1	F□eet □□ti□tie□	GE□□P□T	□	0	0	□□	1	□	□□	□	1□
RBC	□□	Po□tage	C□□TBI□□□	0	0	0	0	0	0	0	0	□□□
RBC	□□	TOT□□ □□ER□GE PREP□□ME□T□		□□0	1□1□□	0	1□0□□	□□	1□□	□□□	□□	1□□□□
RBC	□□											
RBC	□□											
RBC	□□											
RBC	□□											
RBC	□□											
RBC	□0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RBC	1	**OPERATING REVENUES**											
RBC	2												
RBC	3	**SALES REVENUES**											
RBC	4	Sales of Electricity - Base		1	1	1	1	0	1	1	0	1	0
RBC	5	Sales of Electricity - Prior Year Adjustment	E-ERG	1	0	1	0	0	0	0	0	0	0
RBC	6	Transmission Revenue	DTR-R	1	1	0	0	0	1	0	0	0	0
RBC	7	Purchased Electricity Revenue	E-ERG1	1	0	1	0	0	0	0	0	0	0
RBC	8	TOTAL SALES OF ELECTRICITY		1	1	1	1	0	1	1	0	1	0
RBC	9												
RBC	10	**OTHER OPERATING REVENUES**											
RBC	11	Public Authority and Co-Tenant Revenue	E-RE	0	0	0	0	0	0	0	0	0	0
RBC	12	0-Forfeited Discount	OX-0	1	1	1	0	0	11	1	1	1	0
RBC	13	-Rent from Electric Property	TOTP-T	0	1	0	0	0	0	1	1	1	0
RBC	14	-Other Electric Revenue											
RBC	15	Connection Charge-Returned Check Fee	C-T	1	0	0	1	0	0	0	0	0	0
RBC	16	Other	DI-TP-T	1	1	0	1	0	0	1	1	1	0
RBC	17	Total -Other Electric Revenue		1	1	0	0	0	0	1	1	1	0
RBC	18	TOTAL OTHER OPERATING REVE		1	1	1	1	0	11	1	1	1	0
RBC	19												
RBC	20	**TOTAL OPERATING REVENUES**		1	1	1	1	0	1	1	0	1	0
RBC	21												
RBC	22												
RBC	23												
RBC	24												
RBC	25												
RBC	26												
RBC	27												
RBC	28												
RBC	29												
RBC	30												
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RBC	91												
RBC	92												
RBC	93												
RBC	94												
RBC	95												
RBC	96												
RBC	97												
RBC	98												
RBC	99												
RBC	100												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RBC	1	**OPERATING REVENUES**										
RBC												
RBC		**SALES REVENUES**										
RBC		Sale of Electricity Revenue - Base				0						
RBC		Sale of Electricity Revenue - Clear Deco ic	E ERG	0	1	0	0	0	0	0	0	0
RBC		Transmission Revenue	DTR R	0	0	0	0	0	0	0	0	0
RBC		Purchased Electric Revenue	E ERG1	0	1 1 00	0	0	0	0	0	0	0
RBC		TOT ELECTRIC OF ELECTRICIT			1	0						
RBC												
RBC	0	**OTHER OPERATING REVENUES**										
RBC	1	Billed Cost Credit Revenue	E RE	0	0	0	0	0	0	0	0	0
RBC		0-Forfeited Discount	OX 0	1		0			0	1 1		
RBC		-Rent from Electric Property	TOTP T	1	0	0	1	1 0		1		10
RBC		-Other Electric Revenue										
RBC		Connection Charge Returned Check Fee	C T	0	0	0	0	0	0	0	0	
RBC		Other	DI TP T	1 1	0	0		0		0	0	11
RBC		Total -Other Electric Revenue		1 1	0	0		0		0	0	
RBC		TOT OTHER OPER TI G RE				0		1	1	1 0		
RBC												
RBC	0	**TOTAL OPERATING REVENUES**			1 0	0		0	1 1	0	1	0
RBC	1											
RBC												
RBC												
RBC												
RBC												
RBC												
RBC												
RBC												
RBC												
RBC												
RBC	0											
RBC	1											
RBC												
RBC												
RBC												
RBC												
RBC												
RBC												
RBC												
RBC												
RBC												
RBC												
RBC	0											
RBC	1											
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RBC												
RBC												
RBC												
RBC												
RBC												
RBC												
RBC	100											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
E	1	**OPERATION & MAINTENANCE EXPENSE**											
E													
E		PROD□CTIO□ EXPE□□E											
E		Other Po□er □□□□□□											
E		□□□ - P□r□ha□ed Po□er - Ca□a□it□	E□ERG□1	1□00□□□1□	0	1□00□□□1□	0	0	0	0	0	0	0
E		Tota□Other Po□er □□□□□□		1□00□□□1□	0	1□00□□□1□	0	0	0	0	0	0	0
E		TOT□□ PROD□CTIO□ EXPE□□E		1□00□□□1□	0	1□00□□□1□	0	0	0	0	0	0	0
E													
E		TR□□□MI□□IO□ EXPE□□E□											
E	10	O□eratio□ Ex□e□□e	DTR□□R	1□□□□0□	1□□□□0□	0	0	0	1□□□□0□	0	0	0	0
E	11	Mai□te□a□□e Ex□e□□e	DTR□□	0	0	0	0	0	0	0	0	0	0
E	1□	TOT□□ TR□□□MI□□IO□ EXPE□□E		1□□□□0□	1□□□□0□	0	0	0	1□□□□0□	0	0	0	0
E	1□												
E	1□	DI□TRIB□TIO□ EXPE□□E□											
E	1□	O□eratio□											
E	1□	□□0-□□□er□i□io□	□□□□ □GDO	1□□0□	□□□	0	□□□	0	0	□□□	□0□	1□□	0
E	1□	□□1-□oad Di□□at□h	DI□TP□T	0	0	0	0	0	0	0	0	0	0
E	1□	□□□-□tatio□ E□□i□□e□t	P□T□□□□	□1□	□1□	0	0	0	0	□1□	□1□	0	0
E	1□	□□□-O□erhead □i□e□	OHDI□T	1□□□1□	1□□□1□	0	□□□0□	0	0	1□□□1□	□□1□□	□□□□□	0
E	□0	□□□-□□dergro□□d □i□e□	□GDI□T	1□□□□□	11□□00	0	□□□□□	0	0	11□□00	□□□□□	□□□□□	0
E	□1	□□□-□treet □ighti□g	P□T□□□1□	0	0	0	0	0	0	0	0	0	0
E	□□	□□□-Meteri□g	CMETER□	□□□□1	0	0	□□□□1	0	0	0	0	0	0
E	□□	□□□-C□□to□er I□□ta□atio□□	C□□T	1□□□0□	0	0	1□□□0□	0	0	0	0	0	0
E	□□	□□□-Mi□□e□a□eo□□	DI□TP□T	□0□□□1	□□□□□□	0	□□□□□□	0	0	□□□□□□	□□□□01	1□□□□1	0
E	□□	□□□-Re□t□	DI□TP□T	□□□□□	□□□□□	0	□□□□	0	0	□□□□□	1□□□0	□□0	0
E	□□	Tota□Di□trib□tio□ O□eratio□		1□0□□□0	□□□□11	0	□□□□1□	0	0	□□□□11	□□□□□□	□0□□1□	0
E	□□												
E	□□	Mai□te□a□□e											
E	□□	□□0-□□□er□i□io□	□□□□ □GDM	0	0	0	0	0	0	0	0	0	0
E	□0	□□1-□tr□□t□re□	P□T□□□1	□□□□□	□□□□□	0	0	0	0	□□□□□	□□□□□	0	0
E	□1	□□□-□tatio□ E□□i□□e□t	P□T□□□□	1□□□□□	1□□□□□	0	0	0	0	1□□□□□	1□□□□□	0	0
E	□□	□□□-O□erhead □i□e□	OHDI□T	□0□□□□□	1□□□□□□	0	□□□0□1	0	0	1□□□□□□	□□□□□□	□□□1□□	0
E	□□	□□□-□□dergro□□d □i□e□	□GDI□T	□□□1□□	□□□□0□	0	□□□□□	0	0	□□□□0□	□□□□□□	□□□□□	0
E	□□	□□□-Tra□□for□er□	P□T□□□□	□□□□□	□□□□□	0	0	0	0	□□□□□	0	0	0
E	□□	□□□-□treet □ighti□g	P□T□□□□	1□□□□	0	0	1□□□□	0	0	0	0	0	0
E	□□	□□□-Meteri□g	CMETER□	0	0	0	0	0	0	0	0	0	0
E	□□	□□□-Mi□□e□a□eo□□	DI□TP□T	□0□□□□	1□□0□□	0	□□□□1	0	0	1□□0□□	10□□□□	□□□0□	0
E	□□	Tota□Di□trib□tio□ Mai□te□a□□e		□□□□□0□	□□0□□0□	0	□□□□□□	0	0	□□0□□0□	1□□□1□□	□□□□□□	0
E	□□												
E	□0	TOT□□ DI□TRIB□TIO□ P□□□T O□M EXPE□□E□		□□□□□□□	□1□□1□0	0	1□0□□1□	0	0	□1□□1□0	□□0□10□	□□□□□1	0
E	□1	TOT□□ P□RCH□□ED PO□ ER O□M EXPE□□E□		1□00□□□1□	0	1□00□□□1□	0	0	0	0	0	0	0
E	□□	TOT□□ TR□□□MI□□IO□ O□M EXPE□□E□		1□□□□0□	1□□□□0□	0	0	0	1□□□□0□	0	0	0	0
E	□□												
E	□□	TOT□□ OPER □ M□I□T EXP □PROD□TR□□□ DI□T□		1□□□□0□□	□0□0□□	1□00□□□1□	1□0□□1□	0	1□□□□0□	□1□□1□0	□□0□10□	□□□□□1	0
E	□□												
E	□□												
E	□□												
E	□□												
E	□□												
E	□0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
E	1	**OPERATION & MAINTENANCE EXPENSE**										
E												
E		PROD CTIO EXPE E										
E		Other Po er										
E		- P r ha ed Po er - Ca a it	E ERG 1	0	1 00 1	0	0	0	0	0	0	0
E		Tota Other Po er		0	1 00 1	0	0	0	0	0	0	0
E		TOT PROD CTIO EXPE E		0	1 00 1	0	0	0	0	0	0	0
E												
E		TR MI IO EXPE E										
E	10	O eratio Ex e e	DTR R	0	0	0	0	0	0	0	0	0
E	11	Mai te a e Ex e e	DTR	0	0	0	0	0	0	0	0	0
E	1	TOT TR MI IO EXPE E		0	0	0	0	0	0	0	0	0
E	1											
E	1	DI TRIB TIO EXPE E										
E	1	O eratio										
E	1	0- er i io	GDO	1	0	0	1		1	0	0	
E	1	1- oad Di at h	DI TP T	0	0	0	0	0	0	0	0	0
E	1	- tatio E i e t	P T	0	0	0	0	0	0	0	0	0
E	1	- O erhead i e	OHDI T	0	0	0	0	0	0	0	0	0
E	0	- dergro d i e	GDI T	0	0	0	0	0	0	0	0	0
E	1	- treet ighti g	P T 1	0	0	0	0	0	0	0	0	0
E		-Meteri g	CMETER	0	0	0	0	0	1	0	0	0
E		-C to er I ta atio	C T	0	0	0	0	0	0	0	0	1 0
E		-Mi e a eo	DI TP T		0	0	1	0	0	0	0	
E		-Re t	DI TP T	1	0	0		1 0	1	0	0	1
E		Tota Di trib tio O eratio		1 0	0	0	00		11	0	0	1
E												
E		Mai te a e										
E		0- er i io	GDM	0	0	0	0	0	0	0	0	0
E	0	1- tr t re	P T 1	0	0	0	0	0	0	0	0	0
E	1	- tatio E i e t	P T	0	0	0	0	0	0	0	0	0
E		- O erhead i e	OHDI T	0	0	0	0 1	0	0	0	0	0
E		- dergro d i e	GDI T	0	0	0		0	0	0	0	0
E		-Tra for er	P T		0	0	0	0	0	0	0	0
E		- treet ighti g	P T	0	0	0	0	0	0	0	0	1
E		-Meteri g	CMETER	0	0	0	0	0	0	0	0	0
E		-Mi e a eo	DI TP T	1	0	0	0		0	0	0	1 1
E		Tota Di trib tio Mai te a e		1	0	0	0 0 0			0	0	1
E												
E	0	TOT DI TRIB TIO P T O M EXPE E		1	0	0	0		11	0	0	1 0
E	1	TOT P RCH ED PO ER O M EXPE E		0	1 00 1	0	0	0	0	0	0	0
E		TOT TR MI IO O M EXPE E		0	0	0	0	0	0	0	0	0
E												
E		TOT OPER M I T EXP PROD TR DI T		1	1 00 1	0	0		11	0	0	1 0
E												
E												
E												
E												
E												
E	0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
E	1	**OPERATION & MAINTENANCE EXPENSE CONTINUED**											
E													
E		C TOMER CCO T EXPE E											
E		01- er io	GC	0	0	0	0	0	0	0	0	0	0
E		0-Meter Readi g	CMETER		0	0		0	0	0	0	0	0
E		0-C to er Re ord a d Co e tio Ex e e	C TREC	10 0	0	0	10 0	0	0	0	0	0	0
E		0- o e tib e o t	EXP 0				1 1	0			1 1		0
E		0-Mi e a eo C	C TC M		0	0		0	0	0	0	0	0
E		TOT C TOMER CCT EXPE E		1 10			1	0			1 1		0
E	0												
E	1												
E		C TOMER ER ICE EXPE E											
E		0- er io	GC	0	0	0	0	0	0	0	0	0	0
E		0-C to er i ta e	C T T	1 11	0	0	1 11	0	0	0	0	0	0
E		0-I for atio a d erti e e t	C T D T	1 0	0	0	1 0	0	0	0	0	0	0
E		10-Mi e a eo C	C TC M	1 000	0	0	1 000	0	0	0	0	0	0
E		TOT C TOMER ER ICE EXPE E		1 1	0	0	1 1	0	0	0	0	0	0
E													
E		E EXPE E TOT CCT 1 1	C T E		0	0		0	0	0	0	0	0
E	0												
E	1	TOT OPER M I T EXC G		1 0	1	1 00		0	1 1	0 0			0
E													
E		DMI I TR TI E GE ER EXPE E											
E		0- d i i trati e a arie	GE	0	1 0	0	1	0	0	1 0	11 1		0
E		1-Offi e ie Ex e e	GE		1 1	0	1	0	0	1 1	1		0
E		-O t ide er i e E o ed	GE	1		0	1	0	0	1	1	10	0
E		-Pro ert I ra e	DGP T	1	1	0	00	0	0	1	1	10	0
E		-I rie a d Da age	GE	1	1	0		0	0	1 1	1	1	0
E		-E o ee Pe io Be efit	GE	0 0	1	0	1 1	0	0	1	10 1		0
E	0	-Reg ator Co i io	C IMRE	10 1	0			0		1			0
E	1	-D i ate Charge -Credit	C IMRE	1 0				0					0
E		0 -Mi e a eo Ge era											
E		R RH	RE RRH	0	0	0	0	0	0	0	0	0	0
E		G	RE G	0	0	0	0	0	0	0	0	0	0
E		G PD HT	C TCI	0	0	0	0	0	0	0	0	0	0
E		Tra it Chargi g - G	CTCRE R	1	0	0	1	0	0	0	0	0	0
E		Tra it Chargi g - PD HT	CTCRE CI	1	0	0	1	0	0	0	0	0	0
E		Other	C IMRE		1 1			0	1	1 00			0
E		Tota 0 -Mi e a eo Ge era			1 1		1	0	1	1 00			0
E	0	-Mai te a e of Ge era P a t	GE P T		11	0	1 0	0	0	11		1 01	0
E	1	TOT G EXPE E		1 1	1 1		0 0	0	0	1			0
E													
E		**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES**		1	1			0		1	01 0	11	0
E													
E		**TOTAL OPERATION & MAINTENANCE EXPENSES**		00	1 0	1 00		0	1 1	1	01 0	11	0
E													
E													
E													
E													
E	100												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
E	1	**OPERATION & MAINTENANCE EXPENSE CONTINUED**										
E												
E		C TOMER CCO T EXPE E										
E		01- er io	GC	0	0	0	0	0	0	0	0	0
E		0-Meter Readi g	CMETER	0	0	0	0	0		0	0	0
E		0-C to er Re ord a d Co e tio Ex e e	C TREC	0	0	0	0	0	0	10 0	0	0
E		0- o e tib e o t	EXP 0	01		0			1	0	1 0	
E		0-Mi e a eo C	C TC M	0	0	0	0	0	0		0	0
E		TOT C TOMER CCT EXPE E		01		0				1 0	1 0	
E	0											
E	1											
E		C TOMER ER ICE EXPE E										
E		0- er io	GC	0	0	0	0	0	0	0	0	0
E		0-C to er i ta e	C T T	0	0	0	0	0	0	0	1 11	0
E		0-I for atio a d erti e e t	C T D T	0	0	0	0	0	0	0	1 0	0
E		10-Mi e a eo C	C TC M	0	0	0	0	0	0	0	1 000	0
E		TOT C TOMER ER ICE EXPE E		0	0	0	0	0	0	0	1 1	0
E												
E		E EXPE E TOT CCT 1 1	C T E	0	0	0	0	0	0	0		0
E	0											
E	1	TOT OPER M I T EXC G		1	1 00	0	10 1	1	1 10	1 0	1 0	
E												
E		DMI I TR TI E GE ER EXPE E										
E		0- d i i trati e a arie	GE	1	0	0		1		11		1
E		1-Offi e ie Ex e e	GE		0	0	1	1				1
E		-O t ide er i e E o o ed	GE	1 0	0	0	1	0	1	0	1	1
E		-Pro ert I ra e	DGP T		0	0	1				0	
E		-I rie a d Da age	GE	1	0	0	1				1	
E		-E o ee Pe io Be efit	GE		0	0	0	1 0				1 0
E	0	-Reg ator Co i io	C IMRE			0	1 1	1	1			101
E	1	-D i ate Charge -Credit	C IMRE			0	11	1	1	0	10	10
E		0 -Mi e a eo Ge era										
E		R RH	RE RRH	0	0	0	0	0	0	0	0	0
E		G	RE G	0	0	0	0	0	0	0	0	0
E		G PD HT	C TCI	0	0	0	0	0	0	0	0	0
E		Tra it Chargi g - G	CTCRE R	0	0	0	0	0	0	0	0	1
E		Tra it Chargi g - PD HT	CTCRE CI	0	0	0	0	0	0	0	0	1
E		Other	C IMRE			0				1		
E		Tota 0 -Mi e a eo Ge era				0				1		1 00
E	0	-Mai te a e of Ge era P a t	GE P T	100	0	0	1 1		1		1	
E	1	TOT G EXPE E				0	101	0	0	0	00	0
E												
E		**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES**		1 10		0	1 1 0 0	1	1	1	0	01
E												
E		**TOTAL OPERATION & MAINTENANCE EXPENSES**		1 10	1 00 0	0	1 1 0 0	1	1	1	0	01
E												
E												
E												
E												
E	100											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**											
D													
D		I□T□□GIB□E P□□□T EXPE□□E	I□TP□T	□□□□□□	□□□□□□	0	1□□□□□	0	0	□□□□□□	□□□□1□	□0□□	0
D													
D		TR□□□MI□□IO□ P□□□T EXPE□□E	TR□□P□T	0	0	0	0	0	0	0	0	0	0
D													
D		DI□TRIB□TIO□ P□□□T EXPE□□E											
D		□□0-□a□d □ □a□d Right□	P□T□□□0	0	0	0	0	0	0	0	0	0	0
D		□□1-□tr□□t□re□□ I□ □ro□e□e□t□	P□T□□□1	□□□□□	□□□□□	0	0	0	0	□□□□□	□□□□□	0	0
D	10	□□□-□tatio□ E□□i□□e□t	P□T□□□□	□□□□1□	□□□□1□	0	0	0	0	□□□□1□	□□□□1□	0	0
D	11	□□□-Po□e□To□er□□ Fixt□re□	P□T□□□□	□□□□□□	□□□10□	0	□□□□□	0	0	□□□10□	1□□0□□	□□01□	0
D	1□	□□□-O□erhead Co□d□□tor□□ De□i□e□	P□T□□□□	□□□□□□	□□□□□0	0	1□□□□□	0	0	□□□□□0	□□□□□1	1□□□□□	0
D	1□	□□□-□□dergro□□d Co□d□t	P□T□□□□	1□□0□1	1□□□00	0	□□□□1	0	0	1□□□00	10□□11	□□□□□	0
D	1□	□□□-□□dergro□□d Co□d□□tor□□ De□i□e□	P□T□□□□	□0□□□□	□□□□□□	0	1□□□□1	0	0	□□□□□□	□0□□□□	□□10□	0
D	1□	□□□-□i□e Tra□□for□er□	P□T□□□□	□1□□□□	□1□□□□	0	0	0	0	□1□□□□	0	0	0
D	1□	□□□-□er□i□e□	P□T□□□□	□□□□□	0	0	□□□□□	0	0	0	0	0	0
D	1□	□□0-Meter□	P□T□□□0	1□□□10	0	0	1□□□10	0	0	0	0	0	0
D	1□	□□1-I□□ta□atio□o□ C□□to□er Pre□i□e□	P□T□□□1	□	0	0	□	0	0	0	0	0	0
D	1□	□□□-□treet □ighti□g □ □ig□a□□□te□□	P□T□□□□	□0□□	0	0	□0□□	0	0	0	0	0	0
D	□0	□□□-□□□et Retire□e□t Co□t□for Di□trib□tio□P□a□t	DI□TP□TX□R	0	0	0	0	0	0	0	0	0	0
D	□1	TOT□□ DI□TRIB□TIO□ P□□□T EXPE□□E		□□1□0□□	1□□□□□□	0	□□□□□□	0	0	1□□□□□□	11□□□11	□□□□□□	0
D	□□												
D	□□	GE□ER□□ P□□□T EXPE□□E	GE□□P□T	1□□□□□	□□□0□	0	□□□□□	0	0	□□□0□	□□□□0	□□□□0	0
D	□□												
D	□□	COMMO□ P□□□T DEPRECI□TIO□ □□D □MORTI□□1 □□□□ □GE□		□□□□□0	11□□0□	0	11□□□□	0	0	11□□0□	□□□□□	□□□0□	0
D	□□												
D	□□	IIJ□ REG □□□ET □MORTI□□TIO□	TOTP□T	□□□□□	□□□□□	0	□1□1□	0	0	□□□□□	□□□□□	□□□	0
D	□□												
D	□□												
D	□0	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**		□□□□□□□	□□□□□□□	0	10□□□□□	0	0	□□□□□□□	1□□□□1□	□□□□□□	0
D	□1												
D	□□												
D	□□												
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**										
D												
D		I□T□□GIB□E P□□□T EXPE□□E	I□TP□T	□□□□□	0	0	□□□□□	□□□1□	□□1□□	0	0	□1□
D												
D		TR□□□MI□□IO□ P□□□T EXPE□□E	TR□□P□T	0	0	0	0	0	0	0	0	0
D												
D		DI□TRIB□TIO□ P□□□T EXPE□□E										
D		□□0-□a□d □ □a□d Right□	P□T□□□0	0	0	0	0	0	0	0	0	0
D		□□1-□tr□□t□re□□ I□ □ro□e□e□t□	P□T□□□1	0	0	0	0	0	0	0	0	0
D	10	□□□-□tatio□ E□□i□□e□t	P□T□□□□	0	0	0	0	0	0	0	0	0
D	11	□□□-Po□e□To□er□□ Fixt□re□	P□T□□□□	0	0	0	□□□□□	0	0	0	0	0
D	1□	□□□-O□erhead Co□d□□tor□□ De□i□e□	P□T□□□□	0	0	0	1□□□□□	0	0	0	0	0
D	1□	□□□-□□dergro□□d Co□d□it	P□T□□□□	0	0	0	□□□□1	0	0	0	0	0
D	1□	□□□-□□dergro□□d Co□d□□tor□□ De□i□e□	P□T□□□□	0	0	0	1□□□□1	0	0	0	0	0
D	1□	□□□-□i□e Tra□□for□er□	P□T□□□□	□1□□□□	0	0	0	0	0	0	0	0
D	1□	□□□-□er□i□e□	P□T□□□□	0	0	0	0	□□□□□	0	0	0	0
D	1□	□□0-Meter□	P□T□□□0	0	0	0	0	0	1□□□10	0	0	0
D	1□	□□1-I□□ta□latio□ o□ C□□to□er Pre□i□e□	P□T□□□1	0	0	0	0	0	0	0	0	□
D	1□	□□□-□treet □ighti□g □ □ig□a□□□te□ □	P□T□□□□	0	0	0	0	0	0	0	0	□0□□
D	□0	□□□-□□et Retire□e□t Co□t□for Di□trib□tio□ P□a□t	DI□TP□TX□R	0	0	0	0	0	0	0	0	0
D	□1	TOT□□DI□TRIB□TIO□ P□□□T EXPE□□E		□1□□□□	0	0	□0□□□□	□□□□□	1□□□10	0	0	□0□1
D	□□											
D	□□	GE□ER□□P□□□T EXPE□□E	GE□□P□T	□□□□	0	0	□□□□□	□□	□□1	□□□□□	□□□	□1□
D	□□											
D	□□	COMMO□ P□□□T DEPRECI□TIO□ □□D □MORTI□□1□□□□ □GE□		□□□	0	0	□□□□□	10□	□□□	□□□□□	□□□	1□11□
D	□□											
D	□□	IIJ□ REG □□□ET □MORTI□□TIO□	TOTP□T	□□□□	0	0	□□□□	□□0□	□1□□	□□□	□0□	□□□
D	□□											
D	□□											
D	□0	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**		□□□□□□	0	0	□□□□□□	11□□□□	□□□0□□	11□□□□	□□□	□□□1□
D	□1											
D	□□											
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D	□□											
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D	□0											
D	□1											
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
TO	1	**OTHER OPERATING EXPENSES**											
TO													
TO		**TAXES OTHER THAN INCOME TAXES**											
TO		**General Taxes**											
TO		P□RT□ Taxe□	P□T□□□01	□□□□0	□□□□0	0	0	0	0	□□□□0	□□□□0	0	0
TO		Ca□ita□□to□□	C□P□TOC□	0	0	0	0	0	0	0	0	0	0
TO		Pa□ro□Re□ated	□□□□ □GE□	1□□0□1	□□□□0	0	□□□□1	0	0	□□□□0	□□□1□	1□□0□	0
TO		P□ □ □o□a□□e Tax	C□□IMRE□	□□00□	□1□	□□□□	□□□□	0	1□□□	□□□□	□□□□	1□□0	0
TO		P□ Pro□ert□ Tax	TOTP□T	□□□□0	□□□□□□	0	1□□□□□	0	0	□□□□□□	□□□□□□	□□□□	0
TO	10	P□ Cor□orate □oa□Tax	TOTP□T	0	0	0	0	0	0	0	0	0	0
TO	11	Tota□Ge□era□Taxe□		□□□□□□□	1□□□□□□	□□□□	□□□□□□	0	1□□□	1□□□□□□	1□□□□□□	□□□□□□	0
TO	1□												
TO	1□												
TO	1□	**Gross Receipt Tax**											
TO	1□												
TO	1□	P□r□ha□ed Po□er											
TO	1□	Retai□Re□e□□e	C□□C□□□TED	1□0□1□□00	0	1□0□1□□00	0	0	0	0	0	0	0
TO	1□	Forfeited Di□□o□□t□		0	0	0	0	0	0	0	0	0	0
TO	1□	□e□□□Bad Debt		0	0	0	0	0	0	0	0	0	0
TO	□0	Tota□P□r□ha□ed Po□er Re□e□□e	C□□C□□□TED	1□0□1□□00	0	1□0□1□□00	0	0	0	0	0	0	0
TO	□1	Tota□P□r□ha□ed Po□er □ GRT Rate □□□0□	C□□C□□□TED	□□□□01	0	□□□□01	0	0	0	0	0	0	0
TO	□□												
TO	□□	Tra□□□i□□io□											
TO	□□	Retai□Re□e□□e	C□□C□□□TED	1□□□□□1	1□□□□□1	0	0	0	1□□□□□1	0	0	0	0
TO	□□	Forfeited Di□o□□t□		0	0	0	0	0	0	0	0	0	0
TO	□□	□e□□□Bad Debt		0	0	0	0	0	0	0	0	0	0
TO	□□	Tota□Tra□□□i□□io□Re□e□□e	C□□C□□□TED	1□□□□□1	1□□□□□1	0	0	0	1□□□□□1	0	0	0	0
TO	□□	Tota□Tra□□□i□□io□□ GRT Rate □□□0□	C□□C□□□TED	11□□□□	11□□□□	0	0	0	11□□□□	0	0	0	0
TO	□□												
TO	□0	Di□trib□tio□											
TO	□1	Retai□Re□e□□e		1□□□□□1□□	□□1□□□□	□□□1□	□1□□□00	0	1□□□□	□□□□□□□	□□0□□□□	□□□□1□□	0
TO	□□	Forfeited Di□o□□t□	C□□C□□□TED	1□□□□□	□□□□□	□□	□□□0□	0	11	□□□□1	□□1□1	1□□□□	0
TO	□□	□e□□□Bad Debt	C□□C□□□TED	□□□□□□	□□□□□□	□□□	□1□□1□	0	□□	□□□□□□	1□□1□□	□□□□1	0
TO	□□	Tota□Di□trib□tio□Re□e□□e	C□□C□□□TED	1□□□□□□□	□□□□0□□	□□□1□	□0□□□□	0	1□□□0	□□0□□□	□□□□□□□	□1□□□□	0
TO	□□	Tota□Di□trib□tio□□ GRT Rate □□□0□	C□□C□□□TED	□1□□□□	□□□□□0	□□1	□□□□□□	0	□0	□□□□□□	□□□□□□	1□□□□	0
TO	□□												
TO	□□	Tota□Gro□□Re□ei□t□Tax		1□□□□□□	□□□□□□	□□□□□□	□□□□□□	0	11□□□□	□□□□□□	□□□□□□	1□□□□□	0
TO	□□												
TO	□□	TOT□□P□RCH□□ED PO□ ER TOIT EXPE□□E□		□□□□01	0	□□□□01	0	0	0	0	0	0	0
TO	□0	TOT□□TR□□□MI□□IO□ TOIT EXPE□□E□		11□□□□	11□□□□	0	0	0	11□□□□	0	0	0	0
TO	□1	TOT□□DI□TRIB□TIO□ TOIT EXPE□□E□		11□□□□	□□□□□□	1□□1□	□□□□□□	0	□0□	□□□0□□	□1□□11	1□□□□□	0
TO	□□												
TO	□□	**TOTAL TAXES OTHER THAN INCOME**		1□□□□□□	□□□0□□	□□□□1□	□□□□□□	0	11□□□0	□□□0□□	□1□□11	1□□□□□	0
TO	□□												
TO	□□												
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
TO	1	**OTHER OPERATING EXPENSES**										
TO												
TO		**TAXES OTHER THAN INCOME TAXES**										
TO		**General Taxes**										
TO		P□RT□ Taxe□	P□T□□□01	0	0	0	0	0	0	0	0	0
TO		Ca□ita□□to□□	C□P□TOC□	0	0	0	0	0	0	0	0	0
TO		Pa□ro□Re□ated	□□□□ □GE□	1□□	0	0	1□□□0	□0	□□1	□□□□□	1□□	□1□
TO		P□ □ □o□a□□e Tax	C□□IMRE□	□□	□□□	0	□1□	□□	□□	1□□	1□	1□
TO		P□ Pro□ert□Tax	TOTP□T	□1□	0	0	□□□	□□□	1□□	□□	□	□□
TO	10	P□ Cor□orate □oa□Tax	TOTP□T	0	0	0	0	0	0	0	0	0
TO	11	Tota□Ge□era□Taxe□		□□□	□□□	0	□□□□□	□10	□□□	□□□□□	□1□	□□□
TO	1□											
TO	1□											
TO	1□	**Gross Receipt Tax**										
TO	1□											
TO	1□	P□r□ha□ed Po□er										
TO	1□	Retai□Re□e□□e	C□□C□□□TED	0	1□0□1□□00	0	0	0	0	0	0	0
TO	1□	Forfeited Di□□o□□t□		0	0	0	0	0	0	0	0	0
TO	1□	□e□□□Bad Debt		0	0	0	0	0	0	0	0	0
TO	□0	Tota□P□r□ha□ed Po□er Re□e□□e	C□□C□□□TED	0	1□0□1□□00	0	0	0	0	0	0	0
TO	□1	Tota□P□r□ha□ed Po□er □ GRT Rate □□□0□	C□□C□□□TED	0	□□□□01	0	0	0	0	0	0	0
TO	□□											
TO	□□	Tra□□□i□□io□										
TO	□□	Retai□Re□e□□e	C□□C□□□TED	0	0	0	0	0	0	0	0	0
TO	□□	Forfeited Di□□o□□t□		0	0	0	0	0	0	0	0	0
TO	□□	□e□□□Bad Debt		0	0	0	0	0	0	0	0	0
TO	□□	Tota□Tra□□□i□□io□Re□e□□e	C□□C□□□TED	0	0	0	0	0	0	0	0	0
TO	□□	Tota□Tra□□□i□□io□□ GRT Rate □□□0□	C□□C□□□TED	0	0	0	0	0	0	0	0	0
TO	□□											
TO	□0	Di□trib□tio□										
TO	□1	Retai□Re□e□□e		□□□□□□	□□□1□	0	□□□□□□□	□□□0□□	□□□□□□	□0□□□1	□□□□□□	□1□□□
TO	□□	Forfeited Di□□o□□t□	C□□C□□□TED	□1□	□□	0	□□□□□	□□□□	□□0	1□□1□	□□□□	□□□□
TO	□□	□e□□□Bad Debt	C□□C□□□TED	□□□01	□□□□	0	□□□□□	□□□□	1□□□□	□□0□□	1□0□□	□□□□
TO	□□	Tota□Di□trib□tio□Re□e□□e	C□□C□□□TED	□□□1□0	□□□1□	0	□□□□□□□0	□□□□1□	□□□1□□	1□□□□□□	□□□1□□	□0□□0□
TO	□□	Tota□Di□trib□tio□□ GRT Rate □□□0□	C□□C□□□TED	□□□□□	□□1	0	1□□□□□	1□□□□	□□□□□	11□□□0	1□□□0	1□□□□
TO	□□											
TO	□□	Tota□Gro□□Re□ei□t□Tax		□□□□□	□□□□□	0	1□□□□□	1□□□□	□□□□□	11□□□0	1□□□0	1□□□□
TO	□□											
TO	□□	TOT□□P□RCH□□ED PO□ ER TOIT EXPE□□E□		0	□□□□01	0	0	0	0	0	0	0
TO	□0	TOT□□TR□□□MI□□IO□ TOIT EXPE□□E□		0	0	0	0	0	0	0	0	0
TO	□1	TOT□□DI□TRIB□TIO□ TOIT EXPE□□E□		□□□□□	1□□1□	0	1□□□□□	1□□□□	□□□□□	1□□□□□	1□□□□	□□□0□
TO	□□											
TO	□□	**TOTAL TAXES OTHER THAN INCOME**		□□□□□	□□□□1□	0	1□□□□□	1□□□□	□□□□□	1□□□□□	1□□□□	□□□0□
TO	□□											
TO	□□											
TO	□□											
TO	□□											
TO	□□											
TO	□□											
TO	□0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**											
TI													
TI		TOT DI TRIB TIO OPER TI G RE E E		1 1 1			0	0	1 0	1 0	0	1	0
TI		E											
TI		OPER TIO M I T I E CE EXPE E	C C C TED	1				0		1	01 0	11	0
TI		DEPRECI TIO D MORTI TIO EXPE E	C C C TED			0	10	0	0		1 1		0
TI		T XE OTHER TH I COME T XE	C C C TED	11		1 1		0	0	1	1 11	1	0
TI		ET OPER TI G I COME BEFORE T XE		0 1		11	10 11	0	1		1 0		0
TI		E											
TI	10	I TERE T EXPE E Rate Ba e 1 eighted Co t of Debt		1 1	1			0	1	1 0	1		0
TI	11												
TI	1	**BASE TAXABLE DISTRIBUTION INCOME**		1 1 1	1			0	0	1	1		0
TI	1												
TI	1												
TI	1	**CALCULATION OF PA STATE INCOME TAXES**											
TI	1	B E T X B E I COME	C C C TED	1 1 1	1			0	0	1	1		0
TI	1	E											
TI	1	tate Tax De re iatio O er der Boo	TOTP T	0 1	0	0	1	0	0	0	1		0
TI	1	Other d t e t	TOTP T	11	1	0	0	0	0	1		1	0
TI	0	Re air o a e Ded tio	TOTP T	10 100	1	0		0	0	1	10 00		0
TI	1	P T TE T X B E DI TRIB TIO I COME		1 1	1			0	0	1		0	0
TI		O ti atio	TOTP T	0		0	1 0	0	0		1	0	0
TI		**PA STATE INCOME TAXES @ Tax Rate 7.99%**					1	0	0		0	0	0
TI		**PLUS:**											
TI		**DEFERRED STATE INCOME TAXES**											
TI		tate Deferred Taxe	TOTP T	1		0		0	0		0	1 0	0
TI		**DEFERRED STATE INCOME TAXES @ Tax Rate 7.99%**		1 01		0		0	0		1	1	0
TI		**TOTAL DISTRIBUTION STATE INCOME TAX EXPENSE**					1	0	0	01			0
TI													
TI	0	**CALCULATION OF FEDERAL INCOME TAXES**											
TI	1	B E T X B E I COME	C C C TED	1 1 1	1			0	0	1	1		0
TI		E											
TI		P tate I o e Taxe					1	0	0		0	0	0
TI		Federa Tax De re iatio O er der Boo	TOTP T	0 1	1	0		0	0	1	10	1	0
TI		Other d t e t	TOTP T	10	0	0	1	0	0	0		1	0
TI		Re air o a e Ded tio	TOTP T	10 100	1	0		0	0	1	10 00		0
TI		FEDER T X BE DI TRIB TIO I COME		0 0	0		0	0	0		01	1 10	0
TI		**FEDERAL INCOME TAXES @ Tax Rate 21.00%**		1	0	1	1	0				0	0
TI		**PLUS:**											
TI	0	**DEFERRED FEDERAL INCOME TAXES**											
TI	1	Federa Deferred Taxe	TOTP T	1 1 0				0	0		1	1	0
TI		**DEFERRED FEDERAL INCOME TAXES @ Tax Rate 21.00%**			1	0		0	0	1	1	1	0
TI		**LESS:**											
TI		**OTHER TAX ADJUSTMENTS**											
TI		E e tri P a t	TOTP T	0	0	0	0	0	0	0	0	0	0
TI		Co o P a t	GE	0	0	0	0	0	0	0	0	0	0
TI		orti atio of I e t e t Tax Credit	EBT	1	10	0		0	0	10			0
TI		**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**		11 0	10	1	1	0	0	10	01	1 011	0
TI		**TOTAL DISTRIBUTION INCOME TAX EXPENSE**		1 1 1	1	1	0	0	0	1 1	1	1 0	0
TI	0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**										
TI												
TI		TOT DI TRIB TIO OPER TI G RE E E				0						
TI		E										
TI		OPER TIO M I T I E CE EXPE E	C C TED	1 10		0	1 1 0 0	1	1	1	0	01
TI		DEPRECI TIO D MORTI TIO EXPE E	C C TED		0	0		11	0	11		1
TI		T XE OTHER TH I COME T XE	C C TED		1 1	0	1	1		1	1	0
TI		ET OPER TI G I COME BEFORE T XE			11	0	00		0	0	0	
TI		E										
TI	10	I TERE T EXPE E Rate Ba e 1 eighted Co t of Debt		1		0	1	01		00	1	
TI	11											
TI	1	**BASE TAXABLE DISTRIBUTION INCOME**		1 1		0			1		0	
TI	1											
TI	1											
TI	1	**CALCULATION OF PA STATE INCOME TAXES**										
TI	1	B E T X B E I COME	C C TED	1 1		0			1		0	
TI	1	E										
TI	1	tate Tax De re latio O er der Boo	TOTP T		0	0		1 0	1 0	0	1	
TI	1	Other d t e t	TOTP T	1	0	0	1	11				1 0
TI	0	Re air o a e Ded tio	TOTP T	1	0	0	1			1	0	1
TI	1	P T TE T X B E DI TRIB TIO I COME		1 1 1		0	1 0	11 0	10			
TI		O ti latio	TOTP T		0	0	11 1	0	0			
TI		**PA STATE INCOME TAXES @ Tax Rate 7.99%**		1	0	0				0		1
TI		**PLUS:**										
TI		**DEFERRED STATE INCOME TAXES**										
TI		tate Deferred Taxe	TOTP T	1 0	0	0	0					11
TI		**DEFERRED STATE INCOME TAXES @ Tax Rate 7.99%**			0	0	1				0	
TI		**TOTAL DISTRIBUTION STATE INCOME TAX EXPENSE**			0	0			0			1
TI												
TI	0	**CALCULATION OF FEDERAL INCOME TAXES**										
TI	1	B E T X B E I COME	C C TED	1 1		0			1		0	
TI		E										
TI		P tate I o e Taxe		1	0	0				0		1
TI		Federa Tax De re latio O er der Boo	TOTP T	1	0	0			1	0	1	1
TI		Other d t e t	TOTP T		0	0	1		0	1	1	
TI		Re air o a e Ded tio	TOTP T	1	0	0	1			1	0	1
TI		FEDER T X BE DI TRIB TIO I COME		1		0		1				
TI		**FEDERAL INCOME TAXES @ Tax Rate 21.00%**			1	0		1		1	1	10
TI		**PLUS:**										
TI	0	**DEFERRED FEDERAL INCOME TAXES**										
TI	1	Federa Deferred Taxe	TOTP T	10	0	0	1 0	1	1			1 1
TI		**DEFERRED FEDERAL INCOME TAXES @ Tax Rate 21.00%**		1	0	0	1	1 1	1		1	10
TI		**LESS:**										
TI		**OTHER TAX ADJUSTMENTS**										
TI		E e tri P a t	TOTP T	0	0	0	0	0	0	0	0	0
TI		Co o P a t	GE	0	0	0	0	0	0	0	0	0
TI		orti atio of I e t e t Tax Credit	EBT	1	0	0		0	0	0	0	0
TI		**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**		1 0	1	0		1 01	1	0	1	
TI		**TOTAL DISTRIBUTION INCOME TAX EXPENSE**		1	1	0	1	1	0	1 1	0	0
TI	0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
TI	□1	**DEVELOPMENT OF INCOME TAXES CONTINUED**											
TI	□□												
TI	□□	**DEVELOPMENT OF PURCHASED POWER TAXES**											
TI	□□	P□RCH□□ED PO□ ER OPER□TI□G RE□E□□E□	C□□C□□□TED	1□0□1□□00	0	1□0□1□□00	0	0	0	0	0	0	0
TI	□□	□E□□□											
TI	□□	OPER□TIO□ □ M□I□T□I□E□CE EXPE□□E	C□□C□□□TED	1□00□□□1□	0	1□00□□□1□	0	0	0	0	0	0	0
TI	□□	T□XE□ OTHER TH□□ I□COME T□XE□	C□□C□□□TED	□□□□01	0	□□□□01	0	0	0	0	0	0	0
TI	□□	□ET OPER□TI□G I□COME BEFORE T□XE□		□□□□□	0	□□□□□	0	0	0	0	0	0	0
TI	□□	□E□□□											
TI	□0	I□TERE□T EXPE□□E □Rate Ba□e □□□1□□ □ eighted Co□t of Debt□		□□□	0	□□□	0	0	0	0	0	0	0
TI	□1	**BASE TAXABLE PURCHASED POWER INCOME**		□□□□□	0	□□□□□	0	0	0	0	0	0	0
TI	□□	□E□□□											
TI	□□	**PA STATE PURCHASED PWR INCOME TAXES @ Tax Rate 7.99%**		□□□	0	□□□	0	0	0	0	0	0	0
TI	□□	E□ □□□□□											
TI	□□	**FEDERAL PURCHASED PWR INCOME TAXES @ Tax Rate 21.00%**		□□□	0	□□□	0	0	0	0	0	0	0
TI	□□	□dditio□a□P□r□ha□e Po□er Ex□e□□e □O□		0	0	0	0	0	0	0	0	0	0
TI	□□												
TI	□□	**DEVELOPMENT OF TRANSMISSION TAXES**											
TI	□□	TR□□□MI□□IO□ OPER□TI□G RE□E□□E□	C□□C□□□TED	1□□□□□1	1□□□□□1	0	0	0	1□□□□□1	0	0	0	0
TI	□0	□E□□□											
TI	□1	OPER□TIO□ □ M□I□T□I□E□CE EXPE□□E	C□□C□□□TED	1□□□□0□	1□□□□0□	0	0	0	1□□□□0□	0	0	0	0
TI	□□	T□XE□ OTHER TH□□ I□COME T□XE□	C□□C□□□TED	11□□□□	11□□□□	0	0	0	11□□□□	0	0	0	0
TI	□□	□ET OPER□TI□G I□COME BEFORE T□XE□		1□0□□	1□0□□	0	0	0	1□0□□	0	0	0	0
TI	□□	□E□□□											
TI	□□	I□TERE□T EXPE□□E □Rate Ba□e □□□1□□ □ eighted Co□t of Debt□		□11	□11	0	0	0	□11	0	0	0	0
TI	□□	**BASE TAXABLE TRANSMISSION INCOME**		□□□	□□□	0	0	0	□□□	0	0	0	0
TI	□□	□E□□□											
TI	□□	**PA STATE TRANSMISSION INCOME TAXES @ Tax Rate 7.99%**		□1	□1	0	0	0	□1	0	0	0	0
TI	□□	E□ □□□□□											
TI	□0	**FEDERAL TRANSMISSION INCOME TAXES @ Tax Rate 21.00%**		1□1	1□1	0	0	0	1□1	0	0	0	0
TI	□1												
TI	□□	**TOTAL PA INCOME TAX EXPENSE**		□□01□□	□□□□□□	□□1	□1□□□□	0	□1	□□01□□	□□□□□□	□□□□	0
TI	□□	**TOTAL FEDERAL INCOME TAX EXPENSE**		□11□1□□□	□10□0□□□	□□□	□1□□□□	0	□1□	□10□□□□	□□01□□	□1□011□	0
TI	□□	**TOTAL INCOME TAX EXPENSE**		□1□□1□□□	□1□□00□□	□□□	□□0□□□	0	□10	□1□□□1□□	□1□□□□□	□1□□0□	0
TI	□□												
TI	□□												
TI	□□												
TI	□□												
TI	□□	**TAX RATES**											
TI	□0	GRO□□ RECEIPT□ T□X R□TE	□□□0□										
TI	□1	□T□TE T□X R□TE	□□□□□										
TI	□□	□□CO□□ECTIB□E EXPE□□E□	0□00□□1										
TI	□□	FEDER□□ T□X R□TE - C□RRE□T	□1□00□										
TI	□□	P□C □OC□ □ □B□ □□□E□□ME□T R□TE	0□00□□										
TI	□□	EFFECTI□E T□X R□TE	□□□□1□1□										
TI	□□	□PC R□TE	0□00□0□□										
TI	□□	GRO□□ RE□E□□E CO□□ER□IO□ F□CTOR	1□□□□□□□										
TI	□□	**WEIGHTED COST OF DEBT**	□□1□00□										
TI	□□												
TI	100												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
TI	□1	**DEVELOPMENT OF INCOME TAXES CONTINUED**										
TI	□□											
TI	□□	**DEVELOPMENT OF PURCHASED POWER TAXES**										
TI	□□	P□RCH□□ED PO□ ER OPER□TI□G RE□E□□E□	C□□C□□□TED	0	1□0□1□□00	0	0	0	0	0	0	0
TI	□□	□E□□□										
TI	□□	OPER□TIO□ □ M□I□T□I□E□CE EXPE□□E	C□□C□□□TED	0	1□00□□□1□	0	0	0	0	0	0	0
TI	□□	T□XE□ OTHER TH□□ I□COME T□XE□	C□□C□□□TED	0	□□□□01	0	0	0	0	0	0	0
TI	□□	□ET OPER□TI□G I□COME BEFORE T□XE□		0	□□□□□	0	0	0	0	0	0	0
TI	□□	□E□□□										
TI	□0	I□TERE□T EXPE□□E □Rate Ba□e □□1□□ □ eighted Co□t of Debt□		0	□□□	0	0	0	0	0	0	0
TI	□1	**BASE TAXABLE PURCHASED POWER INCOME**		0	□□□□□	0	0	0	0	0	0	0
TI	□□	□E□□□										
TI	□□	**PA STATE PURCHASED PWR INCOME TAXES @ Tax Rate 7.99%**		0	□□□	0	0	0	0	0	0	0
TI	□□	E□□□□□										
TI	□□	**FEDERAL PURCHASED PWR INCOME TAXES @ Tax Rate 21.00%**		0	□□□	0	0	0	0	0	0	0
TI	□□	□dditio□a□P□r□ha□e Po□er Ex□e□□e □O□		0	0	0	0	0	0	0	0	0
TI	□□											
TI	□□	**DEVELOPMENT OF TRANSMISSION TAXES**										
TI	□□	TR□□□MI□□IO□ OPER□TI□G RE□E□□E□	C□□C□□□TED	0	0	0	0	0	0	0	0	0
TI	□0	□E□□□										
TI	□1	OPER□TIO□ □ M□I□T□I□E□CE EXPE□□E	C□□C□□□TED	0	0	0	0	0	0	0	0	0
TI	□□	T□XE□ OTHER TH□□ I□COME T□XE□	C□□C□□□TED	0	0	0	0	0	0	0	0	0
TI	□□	□ET OPER□TI□G I□COME BEFORE T□XE□		0	0	0	0	0	0	0	0	0
TI	□□	□E□□□										
TI	□□	I□TERE□T EXPE□□E □Rate Ba□e □□1□□ □ eighted Co□t of Debt□		0	0	0	0	0	0	0	0	0
TI	□□	**BASE TAXABLE TRANSMISSION INCOME**		0	0	0	0	0	0	0	0	0
TI	□□	□E□□□										
TI	□□	**PA STATE TRANSMISSION INCOME TAXES @ Tax Rate 7.99%**		0	0	0	0	0	0	0	0	0
TI	□□	E□□□□□										
TI	□0	**FEDERAL TRANSMISSION INCOME TAXES @ Tax Rate 21.00%**		0	0	0	0	0	0	0	0	0
TI	□1											
TI	□□	**TOTAL PA INCOME TAX EXPENSE**		□□□□□	□□1	0	□□□□□	□□□□□	□□□0□	□□□	□□	□1□□□
TI	□□	**TOTAL FEDERAL INCOME TAX EXPENSE**		□1□□□0□	□□□	0	□□□	□1□□01□	□1□□□□□	□□□0	□1	□□□□□
TI	□□	**TOTAL INCOME TAX EXPENSE**		□1□□□□	□□□	0	1□□	□1□□□□□	□□□0□□□	1□1□□	□□	□□0□□
TI	□□											
TI	□□											
TI	□□											
TI	□□											
TI	□□	**TAX RATES**										
TI	□0	GRO□□ RECEIPT□ T□X R□TE	□□□0□									
TI	□1	□T□TE T□X R□TE	□□□□□									
TI	□□	□□CO□□ECTIB□E EXPE□□E□	0□00□□1									
TI	□□	FEDER□□ T□X R□TE - C□RRE□T	□1□00□									
TI	□□	P□C □OC□ □ □B□ □□□E□□ME□T R□TE	0□00□□									
TI	□□	EFFECTI□E T□X R□TE	□□□□1□1□									
TI	□□	□PC R□TE	0□00□0□□									
TI	□□	GRO□□ RE□E□□E CO□□ER□IO□ F□CTOR	1□□□□□□□									
TI	□□	**WEIGHTED COST OF DEBT**	□□1□00□									
TI	□□											
TI	100											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	1	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR**											
		PRODUCTION OTHER SALARIES & WAGES EXPENSE											
		-P-ha-ed Po-er	OX-PROD	0	0	0	0	0	0	0	0	0	0
		TOT--PROD-CTIO- OTHER --- - - -G EXP		0	0	0	0	0	0	0	0	0	0
		TRANSMISSION SALARIES & WAGES EXPENSE											
		O-eratio-	OX-TR--	0	0	0	0	0	0	0	0	0	0
		Mai-te-a--e	MX-TR--	0	0	0	0	0	0	0	0	0	0
	10	TOT--TR---MI--IO-		0	0	0	0	0	0	0	0	0	0
	11												
	1-	**DISTRIBUTION SALARIES & WAGES EXPENSE**											
	1-	O-eratio-											
	1-	---O-erhead -i-e-	OX-----	----1	-----	0	----	0	0	------	1-----	----	0
	1-	----d-ergro--d -i-e-	OX-----	----1	--00-	0	----	0	0	--00-	1---0	----	0
	1-	---Meteri-g	OX-----	------	0	0	------	0	0	0	0	0	0
	1-	---C--to-er I--ta-atio--	OX-----	----0	0	0	----0	0	0	0	0	0	0
	1-	---Mi--e-a-eo--	OX-----	------	------	0	----1	0	0	------	------	1----1	0
	1-	Tota-O-eratio-		----1-	10-----	0	1--1--	0	0	10-----	------	------	0
	-0	Mai-te-a--e											
	-1	--1-tr--t-re-	MX----1	1-----	1-----	0	0	0	0	1-----	1-----	0	0
	--	---tatio- E--i--e-t	MX-----	--1--	--1--	0	0	0	0	--1--	--1--	0	0
	--	---O-erhead -i-e-	MX-----	---1-0	----01	0	1------	0	0	----01	-0----	11---1-	0
	--	----d-ergro--d -i-e-	MX-----	1------	1-----0	0	------	0	0	1-----0	10----	----1-	0
	--	---Tra--for-er-	MX-----	--1-	--1-	0	0	0	0	--1-	0	0	0
	--	---treet -ighti-g	MX-----	10-	0	0	10-	0	0	0	0	0	0
	--	---Mi--e-a-eo--	MX-----	------	------	0	1---1-	0	0	------	-----1	--1-	0
	--	Tota-Mai-te-a--e		----01	--1-----	0	1------	0	0	--1-----	--------	1-------	0
	--	TOT--DI-TRIB-TIO-		10----1-	--1---0-	0	--1---1-	0	0	--1---0-	--------	1-------	0
	-0												
	-1	**CUSTOMER ACCOUNTS SAL & WAGES EXP**											
	--	-0-C--to-er Re-ord-a-d Co-e-tio- Ex-e--e	C--TREC	--------	0	0	--------	0	0	0	0	0	0
	--	-0-Mi--e-a-eo--C-	C--TC-M	--1-	0	0	--1-	0	0	0	0	0	0
	--	**TOTAL CUSTOMER ACCOUNTS SAL & WAGES EXP**		---10-	0	0	---10-	0	0	0	0	0	0
	--												
	--	**CUSTOMER SERVICE SAL & WAGES EXP**											
	--	-0-C--to-er ---i-ta--e	C--T---T	1------	0	0	1------	0	0	0	0	0	0
	--	-0-d-erti-e-e-t	C--T-D-T	0	0	0	0	0	0	0	0	0	0
	--	-10-Mi--e-a-eo--C-	C--TC-M	----	0	0	----	0	0	0	0	0	0
	-0	TOT--C--TOMER -ER-ICE --- - - -GE- EXP		1------	0	0	1------	0	0	0	0	0	0
	-1												
	--	**SALES EXPENSE (ACCT 912&916)**	OX-C-	----	0	0	----	0	0	0	0	0	0
	--												
	--	**ADMINISTRATIVE & GENERAL SALARIES & WAGE** ---- -GX-G		----0-	1-----0	0	1-----1	0	0	1-----0	10-----	------	0
	--	**TOT OPER & MAINTENANCE LABOR**		1-------	--------	0	--------	0		--------	--------	-1-----	0
	--												
	--												
	--												
	--												
	-0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
	1	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR**										
		PRODUCTION OTHER SALARIES & WAGES EXPENSE										
		-P-ha-ed Po-er	OX-PROD	0	0	0	0	0	0	0	0	0
		TOT--PROD-CTIO- OTHER ---- - - -G EXP		0	0	0	0	0	0	0	0	0
		TRANSMISSION SALARIES & WAGES EXPENSE										
		O-eratio-	OX-TR--	0	0	0	0	0	0	0	0	0
		Mai-te-a--e	MX-TR--	0	0	0	0	0	0	0	0	0
	10	TOT-- TR--- MI--IO-		0	0	0	0	0	0	0	0	0
	11											
		DISTRIBUTION SALARIES & WAGES EXPENSE										
		O-eratio-										
		-O-erhead -i-e-	OX-----	0	0	0	---	0	0	0	0	0
		--dergro--d -i-e-	OX-----	0	0	0	---	0	0	0	0	0
		-Meteri-g	OX-----	0	0	0	0	0	------	0	0	0
		-C--to-er I--ta-atio--	OX-----	0	0	0	0	0	0	0	0	------0
		-Mi--e-a-eo--	OX-----	---	0	0	1------	-00	---	0	0	--
		Tota-O-eratio-		---	0	0	-0-1	-00	--0-0	0	0	---0-
	0	Mai-te-a--e										
	1	--1--tr--t-re-	MX---1	0	0	0	0	0	0	0	0	0
		-tatio- E--i--e-t	MX-----	0	0	0	0	0	0	0	0	0
		-O-erhead -i-e-	MX-----	0	0	0	1------	0	0	0	0	0
		--dergro--d -i-e-	MX-----	0	0	0	------	0	0	0	0	0
		-Tra--for-er-	MX-----	-1-	0	0	0	0	0	0	0	0
		-treet -ighti-g	MX-----	0	0	0	0	0	0	0	0	10-
		-Mi--e-a-eo--	MX-----	---	0	0	1-00-	---	1--	0	0	--
		Tota-Mai-te-a--e		1-00-	0	0	1------	---	1--	0	0	1---
		TOT-- DI-TRIB-TIO-		1------	0	0	-0------0	---	------	0	0	------
	0											
	1	**CUSTOMER ACCOUNTS SAL & WAGES EXP**										
		0-C--to-er Re-ord-a-d Co-e-tio- Ex-e--e	C--TREC	0	0	0	0	0	0	------	0	0
		0-Mi--e-a-eo--C-	C--TC-M	0	0	0	0	0	0	-1-	0	0
		TOTAL CUSTOMER ACCOUNTS SAL & WAGES EXP		0	0	0	0	0	0	---10-	0	0
		CUSTOMER SERVICE SAL & WAGES EXP										
		0-C--to-er ---i-ta--e	C--T---T	0	0	0	0	0	0	0	1-----	0
		0-d-erti-e-e-t	C--T-D-T	0	0	0	0	0	0	0	0	0
		10-Mi--e-a-eo--C-	C--TC-M	0	0	0	0	0	0	0	---	0
	0	TOT-- C--TOMER -ER-ICE ---- - - -GE- EXP		0	0	0	0	0	0	0	1-----	0
	1											
		SALES EXPENSE (ACCT 912&916)	OX-C-	0	0	0	0	0	0	0	---	0
		ADMINISTRATIVE & GENERAL SALARIES & WAGE ---- -GX-G		---	0	0	-1--	1--	---	------	---	1------
		TOT OPER & MAINTENANCE LABOR		-0--	0	0	---01-	-01	------	-------	-------	-------
	0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
F	1	**ALLOCATION FACTOR TABLE**											
F		**EXTERNALLY DEVELOPED ALLOCATION FACTORS**											
F													
F		**DEMAND**											
F		DEM D - PROD CTIO RE TED											
F		De a d Prod tio	DPROD	0.0000									
F													
F													
F													
F	10												
F	11	DEM D - TR MI IO RE TED											
F	1	De a d Tra i io 1 Coi ide t Pea	DTR	1 1									
F	1												
F	1	De a d Tra i io Re e e	DTR R	1 1									
F	1												
F	1												
F	1												
F	1												
F	1												
F	0	DEM D - DI TRIB TIO RE TED o-Coi ide t Pea De a d											
F	1	De a d Di trib tio Pri ar High Te io	DDI PHT	0									
F		De a d Di trib tio Pri ar O erhead i e	DDI TPO	1									
F		De a d Di trib tio Pri ar dergro d i e	DDI TP	1									
F													
F		De a d Di trib tio e o dar O erhead i e	DDI T O	0.0									
F		De a d Di trib tio e o dar dergro d i e	DDI T	0.0									
F		De a d Di trib tio O erhead i e Tra for er	DDI T OT	0.0									
F		De a d Di trib tio dergro d i e Tra for er	DDI T T	0.0									
F													
F	0												
F	1												
F													
F													
F													
F													
F													
F													
F													
F													
F													
F	0												
F	1												
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F													
F													
F	0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
□F	1	**ALLOCATION FACTOR TABLE**										
□F	□	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
□F	□											
□F	□	**DEMAND**										
□F	□	DEM□□D - PROD□CTIO□ RE□□TED										
□F	□	De□a□d Prod□□tio□	DPROD									
□F	□											
□F	□											
□F	□											
□F	10											
□F	11	DEM□□D - TR□□□MI□□IO□ RE□□TED										
□F	1□	De□a□d Tra□□□i□□io□ □1 Coi□□ide□t Pea□□	DTR□□									
□F	1□											
□F	1□	De□a□d Tra□□□i□□io□ □Re□e□□e□	DTR□□R									
□F	1□											
□F	1□											
□F	1□											
□F	1□											
□F	1□											
□F	□0	DEM□□D - DI□TRIB□TIO□ RE□□TED □□o□-Coi□□ide□t Pea□De□a□d□										
□F	□1	De□a□d Di□trib□tio□ Pri□ar□High Te□□io□	DDI□PHT									
□F	□□	De□a□d Di□trib□tio□ Pri□ar□O□erhead □i□e□	DDI□TPO□									
□F	□□	De□a□d Di□trib□tio□ Pri□ar□□□dergro□□d □i□e□	DDI□TP□□									
□F	□□											
□F	□□	De□a□d Di□trib□tio□ □e□o□dar□ O□erhead □i□e□	DDI□T□O□									
□F	□□	De□a□d Di□trib□tio□ □e□o□dar□ □□dergro□□d □i□e□	DDI□T□□□									
□F	□□	De□a□d Di□trib□tio□ O□erhead □i□e Tra□□for□er□	DDI□T□OT									
□F	□□	De□a□d Di□trib□tio□ □□dergro□□d □i□e Tra□□for□er□	DDI□T□□T									
□F	□□											
□F	□0											
□F	□1											
□F	□□											
□F	□□											
□F	□□											
□F	□□											
□F	□□											
□F	□□											
□F	□□											
□F	□□											
□F	□0											
□F	□1											
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□F	□□											
□F	□0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
F	1	**ALLOCATION FACTOR TABLE CONTINUED**											
F		**EXTERNALLY DEVELOPED ALLOCATION FACTORS**											
F													
F		**ENERGY**											
F		E erg Re e e at ro-for a ad ted e e	E ERG 1	1 0 1 00									
F		E erg Meter M h a e	E ERG	0									
F													
F													
F													
F	0												
F	1												
F													
F													
F													
F		**CUSTOMER**											
F		- C t Di t e o dar OH i e CP	CDI T O	0 0									
F		- C t Di t e o dar G i e CP	CDI T	0 0									
F		- C t Di t e o dar Po e To er Fixt	CDI T O C	1 1 1									
F		- C t Di t e o dar Co d tor De i	CDI T C	1 1 1									
F	0												
F	1	-er i e	C ER ICE										
F		0-Meter	CMETER										
F		1-I ta atio o C to er Pre i e	C TPREM	1 1 1									
F		-treet ighti g ig a te	C IGHT	1									
F													
F		C to er De o it	C TDEP	0000									
F													
F													
F		0-C to er Re ord a d Co e tio	C TREC	0000									
F	0	0-Mi e a eo C to er o t	C TC M	1 1									
F	1	0-C to er i ta e	C T T	0000									
F		0-I for atio a a d I tr tio a d erti i g	C T D T	1 1									
F		10-Mi e a eo C to er er i e	C TC M	1 1									
F		1 1-Mi e a eo a e Ex e e	C T E	1									
F													
F		ber of Bi	C TBI	0									
F		ber of C to er	C T	1 1									
F		ber of Re ide tia C to er	C TRE	1 110									
F		ber of Co er ia a d I d tria C to er	C TCI	1									
F	0												
F	1	Tra it Chargi g - G	CTCRE R	1									
F		Tra it Chargi g - PD HT	CTCRE CI	1									
F													
F													
F													
F													
F													
F													
F													
F	100												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
□F	□1	**ALLOCATION FACTOR TABLE CONTINUED**										
□F	□□	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
□F	□□											
□F	□□	**ENERGY**										
□F	□□	E□erg□Re□e□□e at □ro-for□a ad□□□ted □e□e□	E□ERG□1									
□F	□□	E□erg□□ Meter □M□ h □a□e□□	E□ERG□□									
□F	□□											
□F	□□											
□F	□□											
□F	□0											
□F	□1											
□F	□□											
□F	□□											
□F	□□											
□F	□□	**CUSTOMER**										
□F	□□	□□□ □ □□□ - C□□t□Di□t□□e□o□dar□OH □i□e□ □□CP□	CDI□T□O□									
□F	□□	□□□ □ □□□ - C□□t□Di□t□□e□o□dar□□G □i□e□ □□CP□	CDI□T□□□									
□F	□□	□□□ □ □□□ - C□□t□Di□t□□e□o□dar□Po□e□□To□er□□Fixt	CDI□T□O□C									
□F	□□	□□□ □ □□□ - C□□t□Di□t□□e□o□dar□Co□d□□tor□□ De□i	CDI□T□□□C									
□F	□0											
□F	□1	□□□-□er□i□e□	C□ER□ICE									
□F	□□	□□0-Meter□	CMETER□									
□F	□□	□□1-I□□ta□atio□o□ C□□to□er Pre□i□e□	C□□TPREM									
□F	□□	□□□-□treet □ighti□g □ □ig□a□□□te□□	C□IGHT									
□F	□□											
□F	□□	C□□to□er De□o□it□	C□□TDEP									
□F	□□											
□F	□□											
□F	□□	□0□-C□□to□er Re□ord□a□d Co□e□tio□□	C□□TREC									
□F	□0	□0□-Mi□□e□a□eo□□C□□to□er □□□o□□t□	C□□TC□M									
□F	□1	□0□-C□□to□er □□□i□ta□□e	C□□T□□□T									
□F	□□	□0□-I□for□atio□a□a□d I□□tr□□tio□a□□d□erti□i□g	C□□T□D□T									
□F	□□	□10-Mi□□e□a□eo□□C□□to□er □er□i□e	C□□TC□M									
□F	□□	□1□□1□-Mi□□e□a□eo□□□a□e□Ex□e□□e	C□□T□□□E□									
□F	□□											
□F	□□	□□□ber of Bi□□	C□□TBI□□□									
□F	□□	□□□ber of C□□to□er□	C□□T									
□F	□□	□□□ber of Re□ide□tia□C□□to□er□	C□□TRE□									
□F	□□	□□□ber of Co□□er□ia□a□d I□d□□tria□C□□to□er□	C□□TCI									
□F	□0											
□F	□1	Tra□□it Chargi□g - G□	CTCRE□□□R									
□F	□□	Tra□□it Chargi□g - PD□HT	CTCRE□□□CI									
□F	□□											
□F	□□											
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
□F	101	**ALLOCATION FACTOR TABLE CONTINUED**											
□F	10□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
□F	10□												
□F	10□	**Plant Related**											
□F	10□	I□ta□gib□e P□a□t	I□TP□T	1□□□□□□									
□F	10□	Tra□□□i□□io□ P□a□t i□ □er□□e	TR□□P□T	0									
□F	10□	Di□trib□tio□ P□a□t i□ □er□□e	DI□TP□T	10□□1□□□□□									
□F	10□	Ge□era□P□a□t i□ □er□□e	GE□□P□T	□□□0□□									
□F	10□	Tota□E□e□tri□P□a□t I□ □er□□e	TOTP□T	11□□□□□0□									
□F	110												
□F	111	Di□trib□tio□ P□a□t Ex□□□□et Retire□e□t	DI□TP□TX□R	10□□1□□1□□									
□F	11□	Tota□Tra□□□i□□io□a□d Di□trib□tio□ P□a□t	TDP□T	10□□1□□□□□									
□F	11□	Tota□Di□trib□tio□a□d Ge□era□P□a□t	DGP□T	11□0□□□□□									
□F	11□	Rate Ba□e	R□TEB□□E	□□□□□□□□									
□F	11□												
□F	11□	□□□o□□t □□0	P□T□□□0	□□□1□□									
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□F	11□	□□□o□□t □□□	P□T□□□□	1□□□□□□0□									
□F	1□0	□□□o□□t □□□	P□T□□□□	□□□□□□0□									
□F	1□1	□□□o□□t □□□	P□T□□□□	1□0□□□□□									
□F	1□□	□□□o□□t □□□	P□T□□□□	□□□□□□1□									
□F	1□□	□□□o□□t □□□	P□T□□□□	□□0□□□□									
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□F	1□□	Di□trib□tio□ □ □dergro□□d P□a□t i□ □er□□e	□GDI□T	□□□□□□□□									
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□F	1□□												
□F	1□□	Re□ide□tia□	DP□TRE□	□□□□□1□□									
□F	1□□	Re□ide□tia□Heati□g	DP□TRH	□□□0□□									
□F	1□□	Ge□era□□er□□e	DP□TG□	1□□□□0□□									
□F	1□□	Pri□ar□Di□trib□tio□	DP□TPRID	□□□□1□									
□F	1□□	High Te□□io□	DP□THT	□□□□□□□									
□F	1□□	E□e□tri□Pro□□□io□	DP□TEP	□□□□□□									
□F	1□□	□ighti□g	DP□T□C□□T	□0□□□1									
□F	1□0												
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
□F	101	**ALLOCATION FACTOR TABLE CONTINUED**										
□F	10□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
□F	10□											
□F	10□	**Plant Related**										
□F	10□	I□ta□gib□e P□a□t	I□TP□T									
□F	10□	Tra□□□i□□io□P□a□t i□ □er□□e	TR□□P□T									
□F	10□	Di□trib□tio□P□a□t i□ □er□□e	DI□TP□T									
□F	10□	Ge□era□P□a□t i□ □er□□e	GE□□P□T									
□F	10□	Tota□E□e□tri□P□a□t I□ □er□□e	TOTP□T									
□F	110											
□F	111	Di□trib□tio□P□a□t Ex□□□□et Retire□e□t	DI□TP□TX□R									
□F	11□	Tota□Tra□□□i□□io□a□d Di□trib□tio□P□a□t	TDP□T									
□F	11□	Tota□Di□trib□tio□a□d Ge□era□P□a□t	DGP□T									
□F	11□	Rate Ba□e	R□TEB□□E									
□F	11□											
□F	11□	□□□o□□t □□0	P□T□□□0									
□F	11□	□□□o□□t □□1	P□T□□□1									
□F	11□	□□□o□□t □□□	P□T□□□□									
□F	11□	□□□o□□t □□□	P□T□□□□									
□F	1□0	□□□o□□t □□□	P□T□□□□									
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□F	1□□	□□□o□□t □□□	P□T□□□□									
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□F	1□□	□□□o□□t □□1	P□T□□□1									
□F	1□□	□□□o□□t □□□	P□T□□□□									
□F	1□□	Di□trib□tio□O□erhead P□a□t i□ □er□□e	OHDI□T									
□F	1□□	Di□trib□tio□ □□dergro□□d P□a□t i□ □er□□e	□GDI□T									
□F	1□0	□□□o□□t□□□0 □ □□1	P□T□□□01									
□F	1□1	□□□o□□t□□□1 □ □□□	P□T□□□1□									
□F	1□□											
□F	1□□	Re□ide□tia□	DP□TRE□									
□F	1□□	Re□ide□tia□Heati□g	DP□TRH									
□F	1□□	Ge□era□□er□□e	DP□TG□									
□F	1□□	Pri□ar□Di□trib□tio□	DP□TPRID									
□F	1□□	High Te□□io□	DP□THT									
□F	1□□	E□e□tri□Pro□□□io□	DP□TEP									
□F	1□□	□ighti□g	DP□T□C□□T									
□F	1□0											
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
F	1	ALLOCATION FACTOR TABLE CONTINUED											
F	1	INTERNALLY DEVELOPED ALLOCATION FACTORS											
F	1												
F	1	Production Expense Related											
F	1	[illegible]	OX[illegible]	1[illegible]									
F	1	O[illegible]M Ex[illegible]e Prod[illegible]tio[illegible] Other	OX[illegible]PROD	1[illegible]									
F	1	[illegible]a[illegible]arie[illegible]a[illegible]d [illegible] age[illegible]Prod[illegible]tio[illegible] O[illegible]eratio[illegible]	[illegible] [illegible]GPO	0									
F	1												
F	1												
F	1	Transmission Expense Related											
F	1	Tra[illegible]i[illegible]io[illegible] O[illegible]eratio[illegible] Ex[illegible]e[illegible]e	OX[illegible]TR[illegible]	1[illegible]									
F	1	Tra[illegible]i[illegible]io[illegible] Mai[illegible]te[illegible]a[illegible]e Ex[illegible]e[illegible]e	MX[illegible]TR[illegible]	0									
F	1	Tra[illegible]i[illegible]io[illegible] [illegible]a[illegible]arie[illegible] [illegible] age[illegible] [illegible]o[illegible]t[illegible] [illegible]11-[illegible]	[illegible] [illegible]GTO	0									
F	1	Tra[illegible]i[illegible]io[illegible] [illegible]a[illegible]arie[illegible] [illegible] age[illegible] [illegible]o[illegible]t[illegible] [illegible]-[illegible]	[illegible] [illegible]GTM	0									
F	1												
F	1												
F	1	Distribution Expense Related											
F	1	[illegible]o[illegible]t [illegible]0	OX[illegible]0	1[illegible]0[illegible]									
F	1	[illegible]o[illegible]t [illegible]1	OX[illegible]1	0									
F	1	[illegible]o[illegible]t [illegible]	OX[illegible]	[illegible]1[illegible]									
F	1	[illegible]o[illegible]t [illegible]	OX[illegible]	1[illegible]1[illegible]									
F	1	[illegible]o[illegible]t [illegible]	OX[illegible]	1[illegible]									
F	1	[illegible]o[illegible]t [illegible]	OX[illegible]	0									
F	1	[illegible]o[illegible]t [illegible]	OX[illegible]	[illegible]1									
F	1	[illegible]o[illegible]t [illegible]	OX[illegible]	1[illegible]0[illegible]									
F	1	[illegible]o[illegible]t [illegible]	OX[illegible]	[illegible]0[illegible]1									
F	1	[illegible]o[illegible]t [illegible]	OX[illegible]	[illegible]									
F	1	[illegible]o[illegible]t [illegible]1	MX[illegible]1	[illegible]									
F	1	[illegible]o[illegible]t [illegible]	MX[illegible]	1[illegible]									
F	1	[illegible]o[illegible]t [illegible]	MX[illegible]	[illegible]0[illegible]									
F	1	[illegible]o[illegible]t [illegible]	MX[illegible]	[illegible]1[illegible]									
F	1	[illegible]o[illegible]t [illegible]	MX[illegible]	[illegible]									
F	1	[illegible]o[illegible]t [illegible]	MX[illegible]	1[illegible]									
F	1	[illegible]o[illegible]t [illegible]	MX[illegible]	0									
F	1	[illegible]o[illegible]t [illegible]	MX[illegible]	[illegible]0[illegible]									
F	1	O[illegible]M [illegible]o[illegible]t[illegible] [illegible]1-[illegible]	OX[illegible]DI[illegible]T	1[illegible]									
F	1	O[illegible]M [illegible]o[illegible]t[illegible] [illegible]1-[illegible]	MX[illegible]DI[illegible]T	[illegible]0[illegible]									
F	1												
F	1												
F	1		

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
□F	1□1	**ALLOCATION FACTOR TABLE CONTINUED**										
□F	1□□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
□F	1□□											
□F	1□□	**Production Expense Related**										
□F	1□□	□□□o□□t □□□	OX□□□□									
□F	1□□	O□M Ex□e□□e Prod□□tio□ Other	OX□PROD									
□F	1□□	□a□arie□a□d □ age□Prod□□tio□ O□eratio□	□□□□ □GPO									
□F	1□□											
□F	1□□											
□F	1□0	**Transmission Expense Related**										
□F	1□1	Tra□□□i□□io□O□eratio□ Ex□e□□e	OX□TR□□									
□F	1□□	Tra□□□i□□io□Mai□te□a□□e Ex□e□□e	MX□TR□□									
□F	1□□	Tra□□□i□□io□ □a□arie□□ □ age□□□□o□□t□ □11-□□□	□□□□ □GTO									
□F	1□□	Tra□□□i□□io□ □a□arie□□ □ age□□□□o□□t□ □□□-□□□	□□□□ □GTM									
□F	1□□											
□F	1□□											
□F	1□□	**Distribution Expense Related**										
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□F	1□□	□□□o□□t □□1	OX□□□1									
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□F	1□□	O□M □□□o□□t□ □□1-□□□	OX□DI□T									
□F	1□□	O□M □□□o□□t□ □□1-□□□	MX□DI□T									
□F	1□□											
□F	1□□											
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□F	1□1											
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
□F	□01	**ALLOCATION FACTOR TABLE CONTINUED**											
□F	□0□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
□F	□0□												
□F	□0□	**Customer Distribution Expense Related**											
□F	□0□	□□□o□□t □0□	OX□□0□	□□□									
□F	□0□	□□□o□□t □0□	OX□□0□	10□□□0□									
□F	□0□	□□□o□□t □0□	OX□□0□	□□□□□□									
□F	□0□	O□M □□□o□□t□ □0□-□0□	OX□C□	1□□□10□									
□F	□0□												
□F	□10	□□□o□□t□0□	OX□□0□	1□□□11									
□F	□11	□□□o□□t□0□	OX□□0□	1□□0□									
□F	□1□	□□□o□□t□10	OX□□10	1□000									
□F	□1□	O□M □□□o□□t□ □0□-□10	OX□C□	□1□□1□									
□F	□1□	□□□o□□t□ □01-□10	X□C□C□	1□□□□□□									
□F	□1□												
□F	□1□	Tota□O□M □e□□ P□r□ha□ed Po□er	OMXPP	1□001□□□□									
□F	□1□	Tota□O□M □e□□ PP □e□□Pa□ro□□e□□Pe□□io□	OMXPPPP	□□□□□□0									
□F	□1□												
□F	□1□	**Salaries and Wages Expense Related**											
□F	□□0	□a□arie□ □ □age□ □□□o□□t□ □□1-□□□	□□□□ □GDO	□□□□1□									
□F	□□1	□a□arie□ □ □age□ □□□o□□t□ □□1-□□□	□□□□ □GDM	□□□□01									
□F	□□□	□a□arie□ □ □age□ □□□o□□t□ □0□-□0□	□□□□ □GC□	□□□10□									
□F	□□□	□a□arie□ □ □age□ □□□o□□t□ □0□-□10	□□□□ □GC□	1□□□□									
□F	□□□	□a□arie□ □ □age□Ex□□di□g □d□i□ □Ge□	□□□□ □GX□G	1□□□□□0									
□F	□□□	Tota□□a□arie□a□d □age□Ex□e□□e	□□□□ □GE□	1□□□□□□									
□F	□□□												
□F	□□□	Ba□e Taxab□e I□□o□e	EBT	1□1□□1□									
□F	□□□												
□F	□□□												
□F	□□0												
□F	□□1												
□F	□□□												
□F	□□□												
□F	□□□												
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□F	□□□												
□F	□□□												
□F	□□□												
□F	□□0												
□F	□□1												
□F	□□□												
□F	□□□												
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□F	□□0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
□F	□01	**ALLOCATION FACTOR TABLE CONTINUED**										
□F	□0□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
□F	□0□											
□F	□0□	**Customer Distribution Expense Related**										
□F	□0□	□□□o□□t □0□	OX□□0□									
□F	□0□	□□□o□□t □0□	OX□□0□									
□F	□0□	□□□o□□t □0□	OX□□0□									
□F	□0□	O□M □□□o□□t□ □0□-□0□	OX□C□									
□F	□0□											
□F	□10	□□□o□□t□0□	OX□□0□									
□F	□11	□□□o□□t□0□	OX□□0□									
□F	□1□	□□□o□□t□10	OX□□10									
□F	□1□	O□M □□□o□□t□ □0□-□10	OX□C□									
□F	□1□	□□□o□□t□ □01-□10	X□C□C□									
□F	□1□											
□F	□1□	Tota□O□M □e□□ P□r□ha□ed Po□er	OMXPP									
□F	□1□	Tota□O□M □e□□ PP □e□□Pa□ro□□e□□Pe□□io□	OMXPPPP									
□F	□1□											
□F	□1□	**Salaries and Wages Expense Related**										
□F	□□0	□a□arie□ □ □ age□ □□□o□□t□ □□1-□□□	□□□□ □GDO									
□F	□□1	□a□arie□ □ □ age□ □□□o□□t□ □□1-□□□	□□□□ □GDM									
□F	□□□	□a□arie□ □ □ age□ □□□o□□t□ □0□-□0□	□□□□ □GC□									
□F	□□□	□a□arie□ □ □ age□ □□□o□□t□ □0□-□10	□□□□ □GC□									
□F	□□□	□a□arie□ □ □ age□Ex□□di□g □d□i□ □ Ge□	□□□□ □GX□G									
□F	□□□	Tota□□a□arie□a□d □ age□Ex□e□□e	□□□□ □GE□									
□F	□□□											
□F	□□□	Ba□e Taxab□e I□□o□e	EBT									
□F	□□□											
□F	□□□											
□F	□□0											
□F	□□1											
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□F	□□□											
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□F	□□□											
□F	□□□											
□F	□□□											
□F	□□0											
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□F	□□□											
□F	□□0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
F	1	**REVENUES AND BILLING DETERMINANTS**											
F													
F		Base Rate Related	E RE	1 1									
F													
F		Residential	RE RE	1									
F		Residential Heating	RE RH	1 1									
F		General Power	RE G	1									
F		Primary Distribution	RE PRID										
F		High Tension	RE HT	1									
F	0	Electric Propulsion	RE EP	0									
F	1	Lighting	RE C T	0									
F													
F		RRH	RE RRH	1 10 1 1									
F		GPDHT	RE GPDHT	1									
F		PDHT	RE PDHT	1 1									
F													
F		Calculated Rate Related	C IMRE										
F													
F		Capitalized	C P TOC										
F	0												
F	1												
F		**PRESENT REVENUES/EXPENSES FROM SALES INPUT**											
F													
F		Total Base of Electric Revenue		1									
F		Base of Electric Revenue - Distribution		1 1									
F		Base of Electric Revenue - Year Decision		1									
F													
F													
F													
F	0	Base of Electric Revenue - Transition		1									
F	1												
F		**BILLING DETERMINATE INPUTS**											
F		Number of Customer Bill	C C TED	0									
F		Base Monthly Charge Meter	C C TED	0									
F		Base Monthly - Billed		0									
F													
F													
F		**RATE OF RETURN**											
F	0	Rate of Return Earned	C C TED										
F	1												
F													
F													
F													
F													
F													
F													
F													
F													
F	00												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
□F	□□1	**REVENUES AND BILLING DETERMINANTS**										
□F	□□□											
□F	□□□	Ba□e Rate □a□e□Re□e□□e	□□□E□RE□									
□F	□□□											
□F	□□□	Re□ide□tia□	□RE□RE□									
□F	□□□	Re□ide□tia□Heati□g	□RE□RH									
□F	□□□	Ge□era□□er□□e	□RE□G□									
□F	□□□	Pri□ar□Di□trib□tio□	□RE□PRID									
□F	□□□	High Te□□io□	□RE□HT									
□F	□□0	E□e□tri□Pro□□□□io□	□RE□EP									
□F	□□1	□ighti□g	□RE□□C□□T									
□F	□□□											
□F	□□□	R□RH	□RE□RRH									
□F	□□□	G□PD□HT	□RE□G□PDHT									
□F	□□□	PD□HT	□RE□PDHT									
□F	□□□											
□F	□□□	C□ai□ed Rate □a□e□Re□e□□e	C□□IMRE□									
□F	□□□											
□F	□□□	Ca□ita□□to□□	C□P□TOC□									
□F	□□0											
□F	□□1											
□F	□□□	**PRESENT REVENUES/EXPENSES FROM SALES INPUT**										
□F	□□□											
□F	□□□	Tota□□a□e□of E□e□tri□it□Re□e□□e□										
□F	□□□	□a□e□of E□e□tri□it□Re□e□□e□- Di□trib□tio□										
□F	□□□	□a□e□of E□e□tri□it□Re□e□□e□- □□□ear De□o□ □i□□io□i□g										
□F	□□□											
□F	□□□											
□F	□□□											
□F	□□0	□a□e□of E□e□tri□it□Re□e□□e□- Tra□□□ i□□io□										
□F	□□1											
□F	□□□											
□F	□□□	**BILLING DETERMINATE INPUTS**										
□F	□□□	□□□ber of C□□to□er Bi□□	C□□C□□□TED									
□F	□□□	□□□□a□M□ h □a□e□□ Meter	C□□C□□□TED									
□F	□□□	□□□□a□M□ - Bi□ed										
□F	□□□											
□F	□□□											
□F	□□□	**RATE OF RETURN**										
□F	□□0	Rate of Ret□r□ □E□□a□□ed□	C□□C□□□TED									
□F	□□1											
□F	□□□											
□F	□□□											
□F	□□□											
□F	□□□											
□F	□□□											
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□F	□□□											
□F	□□□											
□F	□00											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
□P	1	**ALLOCATION PROPORTIONS TABLE**											
□P	□	**EXTERNALLY DEVELOPED ALLOCATION FACTOF**											
□P	□												
□P	□												
□P	□	DEM□□D - PROD□CTIO□ RE□□TED											
□P	□	De□a□d Prod□□tio□	DPROD	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□P	□												
□P	□												
□P	□												
□P	10												
□P	11	DEM□□D - TR□□□MI□□IO□ RE□□TED											
□P	1□	De□a□d Tra□□□i□□io□ □1 Coi□□ide□t Pea□□	DTR□□	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
□P	1□												
□P	1□	De□a□d Tra□□□i□□io□ □Re□e□□e□	DTR□□R	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
□P	1□												
□P	1□												
□P	1□												
□P	1□												
□P	1□												
□P	□0	DEM□□D - DI□TRIB□TIO□ RE□□TED □□o□-Coi□□ide											
□P	□1	De□a□d Di□trib□tio□ Pri□ar□High Te□□io□	DDI□PHT	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000	0.00000
□P	□□	De□a□d Di□trib□tio□ Pri□ar□O□erhead □i□e□	DDI□TPO□	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	1.00000	0.00000
□P	□□	De□a□d Di□trib□tio□ Pri□ar□□□dergro□□d □i□e□	DDI□TP□□	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	1.00000	0.00000
□P	□□												
□P	□□	De□a□d Di□trib□tio□ □e□o□dar□ O□erhead □i□e□	DDI□T□O□	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	1.00000
□P	□□	De□a□d Di□trib□tio□ □e□o□dar□ □□dergro□□d □i□e□	DDI□T□□□	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	1.00000
□P	□□	De□a□d Di□trib□tio□ O□erhead □i□e Tra□□for□er□	DDI□T□OT	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
□P	□□	De□a□d Di□trib□tio□ □□dergro□□d □i□e Tra□□for□er□	DDI□T□□T	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
□P	□□												
□P	□0												
□P	□1												
□P	□□												
□P	□□												
□P	□□												
□P	□□												
□P	□□												
□P	□□												
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□P	□1												
□P	□□												
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□P	□0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
P	1	**ALLOCATION PROPORTIONS TABLE**										
P		**EXTERNALLY DEVELOPED ALLOCATION FACTOR**										
P												
P												
P		DEM D - PROD CTIO RE TED										
P		De a d Prod tio	DPROD	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P												
P												
P												
P	10											
P	11	DEM D - TR MI IO RE TED										
P	1	De a d Tra i io 1 Coi ide t Pea	DTR	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1											
P	1	De a d Tra i io Re e e	DTR R	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1											
P	1											
P	1											
P	1											
P	1											
P	0	DEM D - DI TRIB TIO RE TED o -Coi ide										
P	1	De a d Di trib tio Pri ar High Te io	DDI PHT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		De a d Di trib tio Pri ar O erhead i e	DDI TPO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		De a d Di trib tio Pri ar dergro d i e	DDI TP	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P												
P		De a d Di trib tio e o dar O erhead i e	DDI T O	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		De a d Di trib tio e o dar dergro d i e	DDI T	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		De a d Di trib tio O erhead i e Tra for er	DDI T OT	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		De a d Di trib tio dergro d i e Tra for er	DDI T T	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P												
P	0											
P	1											
P												
P												
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P	0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
P	1	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
P		**EXTERNALLY DEVELOPED ALLOCATION FACTORS**											
P													
P		**ENERGY**											
P		E erg Re e at ro-for a ad ted e e	E ERG 1	1 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		E erg Meter M h a e	E ERG	1 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P													
P													
P													
P	0												
P	1												
P													
P													
P													
P		**CUSTOMER**											
P		- C t Di t e o dar OH i e CP	CDI T O	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		- C t Di t e o dar G i e CP	CDI T	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		- C t Di t e o dar Po e To er Fixt	CDI T O C	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		- C t Di t e o dar Co d tor De i	CDI T C	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P	0												
P	1	-er e	C ER ICE	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		0-Meter	CMETER	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		1-I ta atio o C to er Pre i e	C TPREM	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		-treet ighti g ig a te	C IGHT	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P													
P		C to er De o it	C TDEP	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P													
P													
P		0 -C to er Re ord a d Co e tio	C TREC	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P	0	0 -Mi e a eo C to er o t	C TC M	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P	1	0 -C to er i ta e	C T T	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		0 -I for atio a a d l tr tio a d erti g	C T D T	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		10-Mi e a eo C to er er e	C TC M	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		1 1-Mi e a eo a e Ex e e	C T E	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P													
P		ber of Bi	C TBI	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		ber of C to er	C T	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		ber of Re ide tia C to er	C TRE	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		ber of Co er ia a d l d tria C to er	C TCI	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P	0												
P	1	Tra it Chargi g - G	CTCRE R	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P		Tra it Chargi g - PD HT	CTCRE CI	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P													
P													
P													
P													
P													
P													
P													
P	100												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
P	1	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
P		**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
P												
P		**ENERGY**										
P		E erg Re e e at ro-for a ad ted e e	E ERG 1	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		E erg Meter M h a e	E ERG	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P												
P												
P												
P	0											
P	1											
P												
P												
P												
P		**CUSTOMER**										
P		- C t Di t e o dar OH i e CP	CDI T O	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		- C t Di t e o dar G i e CP	CDI T	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		- C t Di t e o dar Po e To er Fixt	CDI T O C	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		- C t Di t e o dar Co d tor De i	CDI T C	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	0											
P	1	-er i e	C ER ICE	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
P		0-Meter	CMETER	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
P		1-I ta atio o C to er Pre i e	C TPREM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P		-treet ighti g g a te	C IGHT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P												
P		C to er De o it	C TDEP	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P												
P												
P		0-C to er Re ord a d Co e tio	C TREC	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
P	0	0-Mi e a eo C to er o t	C TC M	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
P	1	0-C to er i ta e	C T T	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
P		0-I for atio a a d l tr tio a d erti i g	C T D T	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
P		10-Mi e a eo C to er er i e	C TC M	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
P	1	1-Mi e a eo a e Ex e e	C T E	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
P												
P		ber of Bi	C TBI	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P		ber of C to er	C T	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P		ber of Re ide tia C to er	C TRE	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P		ber of Co er ia a d l d tria C to er	C TCI	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P	0											
P	1	Tra it Chargi g - G	CTCRE R	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P		Tra it Chargi g - PD HT	CTCRE CI	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P												
P												
P												
P												
P												
P												
P												
P	100											

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	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
P	101	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
P	10	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
P	10												
P	10	**Plant Related**											
P	10	I ta gib e P a t	I TP T	1 00000	0 01 00	0 00000	0	0 00000	0 00000	0 01 00	0	0 1	0 00000
P	10	Tra i io P a t i er e	TR P T	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P	10	Di trib tio P a t i er e	DI TP T	1 00000	0	0 00000	0	0 00000	0 00000	0	0 0	0 1 1	0 00000
P	10	Ge era P a t i er e	GE P T	1 00000	0	0 00000	0 0	0 00000	0 00000	0	0 1	0 1 0	0 00000
P	10	Tota E e tri P a t I er e	TOTP T	1 00000	0 0	0 00000	0	0 00000	0 00000	0 0	0 0	0 1 1	0 00000
P	110												
P	111	Di trib tio P a t Ex et Retire e t	DI TP TX R	1 00000	0	0 00000	0	0 00000	0 00000	0	0 0	0 1 1	0 00000
P	11	Tota Tra i io a d Di trib tio P a t	TDP T	1 00000	0	0 00000	0	0 00000	0 00000	0	0 0	0 1 1	0 00000
P	11	Tota Di trib tio a d Ge era P a t	DGP T	1 00000	0 0	0 00000	0	0 00000	0 00000	0 0	0 0 0	0 1 1	0 00000
P	11	Rate Ba e	R TEB E	1 00000	0	0 00	0	0 00000	0 00 01	0	0 011	0 1	0 00000
P	11												
P	11	o t 0	P T 0	1 00000	1 00000	0 00000	0 00000	0 00000	0 00000	1 00000	1 00000	0 00000	0 00000
P	11	o t 1	P T 1	1 00000	1 00000	0 00000	0 00000	0 00000	0 00000	1 00000	1 00000	0 00000	0 00000
P	11	o t	P T	1 00000	1 00000	0 00000	0 00000	0 00000	0 00000	1 00000	1 00000	0 00000	0 00000
P	11	o t	P T	1 00000	0 1 00	0 00000	0	0 00000	0 00000	0 1 00	0	0 0	0 00000
P	1 0	o t	P T	1 00000	0 1 00	0 00000	0	0 00000	0 00000	0 1 00	0	0 0	0 00000
P	1 1	o t	P T	1 00000	0 11	0 00000	0 1 00	0 00000	0 00000	0 11	0	0 1	0 00000
P	1	o t	P T	1 00000	0 11	0 00000	0 1 00	0 00000	0 00000	0 11	0	0 1	0 00000
P	1	o t	P T	1 00000	1 00000	0 00000	0 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000
P	1	o t	P T	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P	1	o t 0	P T 0	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P	1	o t 1	P T 1	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P	1	o t	P T	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P	1	Di trib tio O erhead P a t i er e	OHDI T	1 00000	0 1 00	0 00000	0	0 00000	0 00000	0 1 00	0	0 0	0 00000
P	1	Di trib tio dergro d P a t i er e	GDI T	1 00000	0 11	0 00000	0 1 00	0 00000	0 00000	0 11	0	0 1	0 00000
P	1 0	o t 0 0 1	P T 01	1 00000	1 00000	0 00000	0 00000	0 00000	0 00000	1 00000	1 00000	0 00000	0 00000
P	1 1	o t 1 1	P T 1	1 00000	0 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P	1												
P	1	Re ide tia	DP TRE	1 00000	0 1 1	0 00000	0 1	0 00000	0 00000	0 1 1	0	0 0 1	0 00000
P	1	Re ide tia Heati g	DP TRH	1 00000	0	0 00000	0 1	0 00000	0 00000	0	0	0	0 00000
P	1	Ge era er e	DP TG	1 00000	0	0 00000	0 1	0 00000	0 00000	0	0 00 00	0 1	0 00000
P	1	Pri ar Di trib tio	DP TPRID	1 00000	1 00000	0 00000	0 00000	0 00000	0 00000	1 00000	0 00 1	0	0 00000
P	1	High Te io	DP THT	1 00000	1 00000	0 00000	0 00000	0 00000	0 00000	1 00000	1 00000	0 00000	0 00000
P	1	E e tri Pro io	DP TEP	1 00000	1 00000	0 00000	0 00000	0 00000	0 00000	1 00000	1 00000	0 00000	0 00000
P	1	ighti g	DP T C T	1 00000	0 1	0 00000	0 1	0 00000	0 00000	0 1	0 0 0	0 1	0 00000
P	1 0												
P	1 1												
P	1												
P	1												
P	1												
P	1												
P	1												
P	1												
P	1												
P	1 0												

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
□P	101	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
□P	10□	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
□P	10□											
□P	10□	**Plant Related**										
□P	10□	I□ta□gib□e P□a□t	I□TP□T	0.0□1□□	0.00000	0.00000	0.1 □□□□	0.0 □□□□	0.0 □00□	0.00000	0.00000	0.00 □□□
□P	10□	Tra□□□ i□□io□ P□a□t i□ □er□□e	TR□□P□T	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□P	10□	Di□trib□tio□ P□a□t i□ □er□□e	DI□TP□T	0.0 □□0□	0.00000	0.00000	0.1 □□□1	0.0 □□□□	0.0 □□1□	0.00000	0.00000	0.00 □□□
□P	10□	Ge□era□P□a□t i□ □er□□e	GE□ □P□T	0.01 □0□	0.00000	0.00000	0.1 □□0□	0.00 □□1	0.0 □□□□	0.□□00□	0.01 □1□	0.0 □□□□
□P	10□	Tota□E□e□tri□P□a□t I□ □er□□e	TOTP□T	0.0 □□1□	0.00000	0.00000	0.1 □□□□	0.0 □□□□	0.0 □□□□	0.00 □□□	0.000 □□	0.00 □□□
□P	110											
□P	111	Di□trib□tio□ P□a□t Ex□□□□et Retire□e□t	DI□TP□TX□R	0.0 □□0□	0.00000	0.00000	0.1 □□□1	0.0 □□□□	0.0 □□1□	0.00000	0.00000	0.00 □□□
□P	11□	Tota□Tra□□□ i□□io□ a□d Di□trib□tio□ P□a□t	TDP□T	0.0 □□0□	0.00000	0.00000	0.1 □□□1	0.0 □□□□	0.0 □□1□	0.00000	0.00000	0.00 □□□
□P	11□	Tota□Di□trib□tio□ a□d Ge□era□P□a□t	DGP□T	0.0 □□1□	0.00000	0.00000	0.1 □□□□	0.0 □□□0	0.0 □□□□	0.00 □□□	0.000 □□	0.00 □□□
□P	11□	Rate Ba□e	R□TEB□□E	0.0 □□1□	0.00 □□□	0.00000	0.1 □□□□	0.0 □□□□	0.01 □□□	0.0 □1 □□	0.001 □□	0.001 □□
□P	11□											
□P	11□	□□□o□□t □□0	P□T□□□0	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□P	11□	□□□o□□t □□1	P□T□□□1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□P	11□	□□□o□□t □□□	P□T□□□□	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□P	11□	□□□o□□t □□□	P□T□□□□	0.00000	0.00000	0.00000	0.□□□□□	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□0	□□□o□□t □□□	P□T□□□□	0.00000	0.00000	0.00000	0.□□□□□	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□1	□□□o□□t □□□	P□T□□□□	0.00000	0.00000	0.00000	0.□□□1 □□	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□□	□□□o□□t □□□	P□T□□□□	0.00000	0.00000	0.00000	0.□□□1 □□	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□□	□□□o□□t □□□	P□T□□□□	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□□	□□□o□□t □□□	P□T□□□□	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
□P	1□□	□□□o□□t □□0	P□T□□□0	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
□P	1□□	□□□o□□t □□1	P□T□□□1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
□P	1□□	□□□o□□t □□□	P□T□□□□	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
□P	1□□	Di□trib□tio□ O□erhead P□a□t i□ □er□□e	OHDI□T	0.00000	0.00000	0.00000	0.□□□□□	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□□	Di□trib□tio□ □□dergro□□d P□a□t i□ □er□□e	□GDI□T	0.00000	0.00000	0.00000	0.□□□1 □□	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□0	□□□o□□t□ □□0 □ □□1	P□T□□□01	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□1	□□□o□□t□ □□1 □ □□□	P□T□□□1□	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
□P	1□□											
□P	1□□	Re□ide□tia□	DP□TRE□	0.00000	0.00000	0.00000	0.□□□□1	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□□	Re□ide□tia□Heati□g	DP□TRH	0.00000	0.00000	0.00000	0.□□□□1	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□□	Ge□era□□er□□e	DP□TG□	0.00000	0.00000	0.00000	0.1 □□□□	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□□	Pri□ar□Di□trib□tio□	DP□TPRID	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□□	High Te□□io□	DP□THT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□□	E□e□tri□Pro□□□io□	DP□TEP	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□□	□ighti□g	DP□T□C□□T	0.00000	0.00000	0.00000	0.□□□□1	0.00000	0.00000	0.00000	0.00000	0.00000
□P	1□0											
□P	1□1											
□P	1□□											
□P	1□□											
□P	1□□											
□P	1□□											
□P	1□□											
□P	1□□											
□P	1□□											
□P	1□□											
□P	1□0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
P	1	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
P	1	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
P	1												
P	1	**Production Expense Related**											
P	1	o t	OX	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	O M Exe e Prod tio Other	OX PROD	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	a arie a d age Prod tio O eratio	GPO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1												
P	1	**Transmission Expense Related**											
P	1	Tra i io O eratio Exe e	OX TR	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
P	1	Tra i io Mai te a e Exe e	MX TR	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	Tra i io a arie age o t 11-	GTO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	Tra i io a arie age o t --	GTM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1												
P	1												
P	1	**Distribution Expense Related**											
P	1	o t 0	OX 0	1.00000	0.00001	0.00000	0.00000	0.00000	0.00000	0.00001	0.01	0.10 0	0.00000
P	1	o t 1	OX 1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	OX	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000	0.00000
P	1	o t	OX	1.00000	0.001 00	0.00000	0.00000	0.00000	0.00000	0.001 00	0.00000	0.00000	0.00000
P	1	o t	OX	1.00000	0.00011	0.00000	0.001 00	0.00000	0.00000	0.00011	0.00000	0.1 00	0.00000
P	1	o t	OX	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	OX	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	OX	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	OX	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.10 0	0.1 01	0.00000
P	1	o t	OX	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.10 0	0.1 01	0.00000
P	1	o t 1	MX 1	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000	0.00000
P	1	o t	MX	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000	0.00000
P	1	o t	MX	1.00000	0.001 00	0.00000	0.00000	0.00000	0.00000	0.001 00	0.00000	0.00000	0.00000
P	1	o t	MX	1.00000	0.00011	0.00000	0.001 00	0.00000	0.00000	0.00011	0.00000	0.1 00	0.00000
P	1	o t	MX	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
P	1	o t	MX	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	MX	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	MX	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00 0	0.1 01	0.00000
P	1	O M o t 1-	OX DI T	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.1 00	0.00000
P	1	O M o t 1-	MX DI T	1.00000	0.0000 0	0.00000	0.000 0 1	0.00000	0.00000	0.0000 0	0.00000	0.00 11	0.00000
P	1												
P	1												
P	1	0											
P	1	1											
P	1												
P	1												
P	1												
P	1												
P	1												
P	1												
P	1												
P	1												
P	00												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
P	1 1	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
P	1	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
P	1											
P	1	**Production Expense Related**										
P	1	o t	OX	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	O M Ex e e Prod tio Other	OX PROD	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	a arie a d age Prod tio O eratio	GPO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1											
P	1 0	**Transmission Expense Related**										
P	1 1	Tra i io O eratio Ex e e	OX TR	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	Tra i io Mai te a e Ex e e	MX TR	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	Tra i io a arie age o t 11-	GTO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	Tra i io a arie age o t -	GTM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1											
P	1											
P	1	**Distribution Expense Related**										
P	1	o t 0	OX 0	0.0 10	0.00000	0.00000	0.1	0.01	0.1	0.00000	0.00000	0 1 0
P	1	o t 1	OX 1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1 0	o t	OX	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1 1	o t	OX	0.00000	0.00000	0.00000	0	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	OX	0.00000	0.00000	0.00000	0 1	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	OX	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	OX	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
P	1	o t	OX	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P	1	o t	OX	0.0 0	0.00000	0.00000	0.1 1	0.0	0.0 1	0.00000	0.00000	0.00
P	1	o t	OX	0.0 0	0.00000	0.00000	0.1 1	0.0	0.0 1	0.00000	0.00000	0.00
P	1	o t 1	MX 1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	MX	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1 0	o t	MX	0.00000	0.00000	0.00000	0	0.00000	0.00000	0.00000	0.00000	0.00000
P	1 1	o t	MX	0.00000	0.00000	0.00000	0 1	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	MX	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	MX	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
P	1	o t	MX	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	o t	MX	0.0 0	0.00000	0.00000	0.1 1	0.0	0.0 1	0.00000	0.00000	0.00
P	1	O M o t 1-	OX DI T	0.0 00	0.00000	0.00000	0.1 00	0.0	0.0 1	0.00000	0.00000	0.10
P	1	O M o t 1-	MX DI T	0.01 10	0.00000	0.00000	0	0.00	0.00	0.00000	0.00000	0.00
P	1											
P	1											
P	1 0											
P	1 1											
P	1											
P	1											
P	1											
P	1											
P	1											
P	1											
P	1											
P	1											
P	00											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
P	01	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
P	0	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
P	0												
P	0	**Customer Distribution Expense Related**											
P	0	t 0	OX 0	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	0	t 0	OX 0	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	0	t 0	OX 0	1.00000	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	0	M t 0-0	OX C	1.00000	0.1 0	0.001	0.00000	0.00000	0.00000	0.1	0.0	0.0	0.00000
P	0												
P	10	t 0	OX 0	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	11	t 0	OX 0	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	t 10	OX 10	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	M t 0-10	OX C	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P	1	t 01-10	X C C	1.00000	0.1 0	0.001	0.00001	0.00000	0.000	0.1 0	0.0 0	0.0	0.00000
P	1												
P	1	Tota O M e P r ha ed Po er	OMXPP	1.00000	0.1 1	0.00	0.00001	0.00000	0.1	0.0	0.01	0.11 10	0.00000
P	1	Tota O M e PP e Pa ro e Pe io	OMXPPPP	1.00000	0.00000	0.00 0	0.00000	0.00000	0.00000	0.1 1	0.00000	0.10	0.00000
P	1												
P	1	**Salaries and Wages Expense Related**											
P	0	a arie age o t 1-	GDO	1.00000	0.00001	0.00000	0.00000	0.00000	0.00000	0.00001	0.1	0.10 0	0.00000
P	1	a arie age o t 1-	GDM	1.00000	0.00000	0.00000	0.00001	0.00000	0.00000	0.00000	0.00000	0.1	0.00000
P		a arie age o t 0-0	GC	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		a arie age o t 0-10	GC	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
P		a arie age Ex di g d i Ge	GX G	1.00000	0.00000	0.00000	0.00 0	0.00000	0.00000	0.00000	0.00 1	0.1	0.00000
P		Tota a arie a d age Ex e e	GE	1.00000	0.00000	0.00000	0.00 0	0.00000	0.00000	0.00000	0.00 1	0.1 0	0.00000
P													
P		Ba e Taxab e I o e	EBT	1.00000	0.00000	0.000	0.00 1	0.00000	0.001	0.00000	0.00000	0.1 10	0.00000
P													
P													
P	0												
P	1												
P													
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P	0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
P	01	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
P	0	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
P	0											
P	0	**Customer Distribution Expense Related**										
P	0	o t 0	OX 0	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
P	0	o t 0	OX 0	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
P	0	o t 0	OX 0	0.0 0	0.00	0.00000	0. 0	0.01	0.0 1	0.1	0.0	0.01
P	0	O M o t 0 - 0	OX C	0.01 1	0.001	0.00000	0.0 0	0.00	0.01	0. 1	0.00	0.00
P	0											
P	10	o t 0	OX 0	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
P	11	o t 0	OX 0	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
P	1	o t 10	OX 10	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
P	1	O M o t 0 - 10	OX C	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
P	1	o t 01 - 10	X C C	0.01 0	0.001	0.00000	0.0	0.00	0.01 0	0.	0.1 1	0.00
P	1											
P	1	Tota O M e P r ha ed Po er	OMXPP	0.01 1	0.00	0.00000	0.1 0	0.00 1	0.01	0.1	0.0	0.0
P	1	Tota O M e PP e Pa ro e Pe io	OMXPPPP	0.01	0.00 0	0.00000	0.1 0	0.00	0.01 1	0.1 1	0.0 0	0.0 0
P	1											
P	1	**Salaries and Wages Expense Related**										
P	0	a arie age o t 1-	GDO	0.0 10	0.00000	0.00000	0.1	0.01	0.1	0.00000	0.00000	0. 1 0
P	1	a arie age o t 1-	GDM	0.01	0.00000	0.00000	0. 0	0.00	0.00	0.00000	0.00000	0.001
P		a arie age o t 0 - 0	GC	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
P		a arie age o t 0 - 10	GC	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
P		a arie age Ex di g d i Ge	GX G	0.01 0	0.00000	0.00000	0.1	0.00	0.0 1	0. 0	0.01	0.0 1
P		Tota a arie a d age Ex e e	GE	0.01 0	0.00000	0.00000	0.1 0	0.00 1	0.0	0. 00	0.01 1	0.0
P												
P		Ba e Taxab e I o e	EBT	0.0 1	0.000	0.00000	0.	0.0	0.00 0	0.0	0.00	0.00
P												
P												
P	0											
P	1											
P												
P												
P												
P												
P												
P												
P												
P	0											
P	1											
P												
P												
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P												
P												
P												
P												
P												
P	0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
P	1	**REVENUES AND BILLING DETERMINANTS**											
P													
P		Ba e Rate a e Re e e	E RE	1 00000	0 0 0	0 00 11	0 01	0 00000	0 000	0 0 01	0 1 1	0 1 1	0 00000
P													
P		Re ide tia	RE RE	1 00000	0	0 00 1	0 01	0 00000	0 000 0	0	0 0	0 1	0 00000
P		Re ide tia Heati g	RE RH	1 00000	0	0 00	0	0 00000	0 000	0	0 00	0 1 0	0 00000
P		Ge era er e	RE G	1 00000	0	0 00 1	0	0 00000	0 000	0 1	0	0 1	0 00000
P		Pri ar Di trib tio	RE PRID	1 00000	0	0 00	0 1	0 00000	0 000	0 0	0	0 1	0 00000
P		High Te io	RE HT	1 00000	0 11	0 010 0	0 0	0 00000	0 000	0	0	0 00000	0 00000
P	0	E e tri Pro io	RE EP	1 00000	0 11	0 00 0	0 01 10	0 00000	0 000	0	0	0 00000	0 00000
P	1	ighti g	RE C T	1 00000	0	0 00100	0 1	0 00000	0 0000	0	0 1 0	0 0	0 00000
P													
P		R RH	RE RRH	1 00000	0 1	0 00	0	0 00000	0 000 1	0 1	0 0	0 1	0 00000
P		G PD HT	RE G PDHT	1 00000	0 1 0	0 00 0	0 1 0	0 00000	0 000	0 0	0	0 1	0 00000
P		PD HT	RE PDHT	1 00000	0 1 0	0 010	0 0 1	0 00000	0 000	0 0	0 0	0 010 1	0 00000
P													
P		Cai ed Rate a e Re e e	C IMRE	1 00000	0 0	0	0 1	0 00000	0 0 0	0	0	0	0 00000
P													
P		Ca ita to	C P TOC	1 00000	0	0 0	0 0	0 00000	0 01	0	0 1	0 1	0 00000
P	0												
P	1												
P		**PRESENT REVENUES/EXPENSES FROM SALES IN**											
P													
P		Tota a e of E e tri it Re e e		1 00000	1 00	1 00000	1 00	1 00	1 00	1 00	1 00	1 00	1 00
P		a e of E e tri it Re e e - Di trib tio		1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000
P		a e of E e tri it Re e e - ear De o i io		1 00000	0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P													
P													
P													
P	0	a e of E e tri it Re e e - Tra i io		1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000
P	1												
P													
P													
P													
P													
P													
P													
P													
P													
P													
P	0												
P	1												
P													
P													
P													
P													
P													
P													
P													
P													
P													
P	00												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
P	1	**REVENUES AND BILLING DETERMINANTS**										
P												
P		Ba e Rate a e Re e e	E RE	0 0	0 00 11	0 00000	0 1 0	0 01	0 0 111	0 1	0 01 1	0 01
P												
P		Re ide tia	RE RE	0 0	0 00 1	0 00000	0 0	0 01	0 0 1	0 1 0	0 0 1	0 0 0
P		Re ide tia Heati g	RE RH	0 0 1	0 00	0 00000	0 1	0 00	0 0	0 1	0 0 00	0 01 00
P		Ge era er e	RE G	0 0 1	0 00 1	0 00000	0 0	0 0	0 0	0 0	0 00 1	0 00 1
P		Pri ar Di trib tio	RE PRID	0 00000	0 00	0 00000	0 00000	0 00	0 0 1 0	0 1 1	0 0011	0 00 0
P		High Te io	RE HT	0 00000	0 010 0	0 00000	0 00000	0 000	0 01 01	0 0 0	0 001	0 00
P	0	E e tri Pro io	RE EP	0 00000	0 00 0	0 00000	0 00000	0 00000	0 00	0 01	0 0000	0 0000
P	1	ighti g	RE C T	0 0	0 00100	0 00000	0 1	0 00000	0 00000	0 0	0 1	0
P												
P		R RH	RE RRH	0 0 11	0 00	0 00000	0 1	0 01	0 0	0 1	0 0	0 01 0
P		G PD HT	RE G PDHT	0 0 1	0 00 0	0 00000	0 0 0	0 0	0 0 0	0 0	0 00	0 00
P		PD HT	RE PDHT	0 00000	0 010	0 00000	0 00000	0 0010	0 01 1	0 0 1	0 001	0 00
P												
P		C ai ed Rate a e Re e e	C IMRE	0 0	0	0 00000	0 10 0	0 01	0 01	0 0	0 00	0 00
P												
P		Ca ita to	C P TOC	0 0	0 0	0 00000	0 1	0 0 0	0 0 0	0 01	0 00	0 00
P	0											
P	1											
P		**PRESENT REVENUES/EXPENSES FROM SALES IN**										
P												
P		Tota a e of E e tri it Re e e		1 00	1 00000	1 00	1 00	1 00	1 00	1 00	1 00	1 00
P		a e of E e tri it Re e e - Di trib tio		1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000
P		a e of E e tri it Re e e - ear De o i io		0 00000	1 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000
P												
P												
P												
P	0	a e of E e tri it Re e e - Tra i io		1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000	1 00000
P	1											
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
□D□	1	**ALLOCATED DIRECT ASSIGNMENTS**											
□D□	□	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**											
□D□	□												
□D□	□	**Net Write-Offs**											
□D□	□	Re□ide□tia□	□RE□RE□	□0.00□□□□1	□0.00□□□□1	□0.00□□□□1	□0.00□□□□1	□0.00□□□□1	□0.00□□□□1	□0.00□□□□1	□0.00□□□□1	□0.00□□□□1	□0.00□□□□1
□D□	□	Re□ide□tia□Heati□g	□RE□RH	1□□□□□□□□□	1□□□□□□□□□	1□□□□□□□□□	1□□□□□□□□□	1□□□□□□□□□	1□□□□□□□□□	1□□□□□□□□□	1□□□□□□□□□	1□□□□□□□□□	1□□□□□□□□□
□D□	□	Ge□era□□er□□e	□RE□G□	□□□□□□□□□	□□□□□□□□□	□□□□□□□□□	□□□□□□□□□	□□□□□□□□□	□□□□□□□□□	□□□□□□□□□	□□□□□□□□□	□□□□□□□□□	□□□□□□□□□
□D□	□	Pri□ar□ Di□trib□tio□	□RE□PRID	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□
□D□	□	High Te□□io□	□RE□HT	1□0□□□0□□	1□0□□□0□□	1□0□□□0□□	1□0□□□0□□	1□0□□□0□□	1□0□□□0□□	1□0□□□0□□	1□0□□□0□□	1□0□□□0□□	1□0□□□0□□
□D□	10	E□e□tri□Pro□□□io□	□RE□EP	0	0	0	0	0	0	0	0	0	0
□D□	11	□ighti□g	□RE□□C□□T	□□□1□	□□□1□	□□□1□	□□□1□	□□□1□	□□□1□	□□□1□	□□□1□	□□□1□	□□□1□
□D□	1□												
□D□	1□												
□D□	1□	Tota□□ rite-Off□	EXP□□0□	10□□□□1□□□□	10□□□□1□□□□	10□□□□1□□□□	10□□□□1□□□□	10□□□□1□□□□	10□□□□1□□□□	10□□□□1□□□□	10□□□□1□□□□	10□□□□1□□□□	10□□□□1□□□□
□D□	1□												
□D□	1□	Tota□□ rite-Off□	EXP□□0□	1.00000	0.□□□□1□	0.00□□□□	0.□□□0□□	0.00000	0.000□1	0.□□□□□□	0.□□□0□□	0.1□□□□	0.00000
□D□	1□												
□D□	1□	□dditio□a□□et □ rite-Off□at C□ai□ed Rate	EXP□□0□	0	0	0	0	0	0	0	0	0	0
□D□	1□												
□D□	□0												
□D□	□1												
□D□	□□	**Customer Advances for Construction**											
□D□	□□	Re□ide□tia□	DP□TRE□	□□□□□□1□□	□□□□□□1□□	□□□□□□1□□	□□□□□□1□□	□□□□□□1□□	□□□□□□1□□	□□□□□□1□□	□□□□□□1□□	□□□□□□1□□	□□□□□□1□□
□D□	□□	Re□ide□tia□Heati□g	DP□TRH	□□□□0□□	□□□□0□□	□□□□0□□	□□□□0□□	□□□□0□□	□□□□0□□	□□□□0□□	□□□□0□□	□□□□0□□	□□□□0□□
□D□	□□	Ge□era□□er□□e	DP□TG□	1□□□□□0□□	1□□□□□0□□	1□□□□□0□□	1□□□□□0□□	1□□□□□0□□	1□□□□□0□□	1□□□□□0□□	1□□□□□0□□	1□□□□□0□□	1□□□□□0□□
□D□	□□	Pri□ar□ Di□trib□tio□	DP□TPRID	□□□□1□	□□□□1□	□□□□1□	□□□□1□	□□□□1□	□□□□1□	□□□□1□	□□□□1□	□□□□1□	□□□□1□
□D□	□□	High Te□□io□	DP□THT	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□
□D□	□□	E□e□tri□Pro□□□io□	DP□TEP	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□
□D□	□□	□ighti□g	DP□T□C□□T	□0.□□□1	□0.□□□1	□0.□□□1	□0.□□□1	□0.□□□1	□0.□□□1	□0.□□□1	□0.□□□1	□0.□□□1	□0.□□□1
□D□	□0												
□D□	□1												
□D□	□□	C□□to□er □d□a□□e□for Co□□tr□□tio□	C□□T□D□	□□□0.□□□□□	□□□0.□□□□□	□□□0.□□□□□	□□□0.□□□□□	□□□0.□□□□□	□□□0.□□□□□	□□□0.□□□□□	□□□0.□□□□□	□□□0.□□□□□	□□□0.□□□□□
□D□	□□												
□D□	□□	C□□to□er □d□a□□e□for Co□□tr□□tio□	C□□T□D□	1.00000	0.□□□□□□	0.00000	0.□□□1□□	0.00000	0.00000	0.□□□□□□	0.□□□□□1	0.□□1□□□	0.00000
□D□	□□												
□D□	□□												
□D□	□□	**Purchase of Receivables**											
□D□	□□	Re□ide□tia□	□RE□RE□	□□□□□□□0	□□□□□□□0	□□□□□□□0	□□□□□□□0	□□□□□□□0	□□□□□□□0	□□□□□□□0	□□□□□□□0	□□□□□□□0	□□□□□□□0
□D□	□□	Re□ide□tia□Heati□g	□RE□RH	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□	□□□□□□□
□D□	□0	Ge□era□□er□□e	□RE□G□	□□□□□00	□□□□□00	□□□□□00	□□□□□00	□□□□□00	□□□□□00	□□□□□00	□□□□□00	□□□□□00	□□□□□00
□D□	□1	Pri□ar□ Di□trib□tio□	□RE□PRID	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□
□D□	□□	High Te□□io□	□RE□HT	□□□□□□□□	□□□□□□□□	□□□□□□□□	□□□□□□□□	□□□□□□□□	□□□□□□□□	□□□□□□□□	□□□□□□□□	□□□□□□□□	□□□□□□□□
□D□	□□	E□e□tri□Pro□□□io□	□RE□EP	0	0	0	0	0	0	0	0	0	0
□D□	□□	□ighti□g	□RE□□C□□T	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□	□□□□□□
□D□	□□												
□D□	□□												
□D□	□□	Tota□POR	POR	1□0□□□□0□	1□0□□□□0□	1□0□□□□0□	1□0□□□□0□	1□0□□□□0□	1□0□□□□0□	1□0□□□□0□	1□0□□□□0□	1□0□□□□0□	1□0□□□□0□
□D□	□□												
□D□	□□	Tota□POR	POR	1.00000	0.□□□□□0	0.00□□□□	0.□□□□□□	0.00000	0.000□□	0.□□□□□□	0.□□□□□□	0.1□□□□	0.00000
□D□	□0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
	1	**ALLOCATED DIRECT ASSIGNMENTS**										
		DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS										
		Net Write-Offs										
		Re ide tia	RE RE	0.00 1	0.00 1	0.00 1	0.00 1	0.00 1	0.00 1	0.00 1	0.00 1	0.00 1
		Re ide tia Heati g	RE RH	1	1	1	1	1	1	1	1	1
		Ge era er i e	RE G									
		Pri ar Di trib tio	RE PRID									
		High Te io	RE HT	1.0 0	1.0 0	1.0 0	1.0 0	1.0 0	1.0 0	1.0 0	1.0 0	1.0 0
	10	E e tri Pro io	RE EP	0	0	0	0	0	0	0	0	0
	11	ighti g	RE C T	1	1	1	1	1	1	1	1	1
		Tota rite-Off	EXP 0	10 1	10 1	10 1	10 1	10 1	10 1	10 1	10 1	10 1
		Tota rite-Off	EXP 0	0.0 0	0.00	0.00000	0 0	0.01	0.0 1	0.1	0.0	0.01
		dditio a et rite-Off at C ai ed Rate	EXP 0	0	0	0	0	0	0	0	0	0
	0											
	1											
		Customer Advances for Construction										
		Re ide tia	DP TRE	1	1	1	1	1	1	1	1	1
		Re ide tia Heati g	DP TRH	0	0	0	0	0	0	0	0	0
		Ge era er i e	DP TG	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0
		Pri ar Di trib tio	DP TPRID	1	1	1	1	1	1	1	1	1
		High Te io	DP THT									
		E e tri Pro io	DP TEP									
		ighti g	DP T C T	0 1	0 1	0 1	0 1	0 1	0 1	0 1	0 1	0 1
	0											
	1											
		C to er d a e for Co tr tio	C T D	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
		C to er d a e for Co tr tio	C T D	0.00000	0.00000	0.00000	0 1	0.00000	0.00000	0.00000	0.00000	0.00000
		Purchase of Receivables										
		Re ide tia	RE RE	0	0	0	0	0	0	0	0	0
		Re ide tia Heati g	RE RH									
	0	Ge era er i e	RE G	00	00	00	00	00	00	00	00	00
	1	Pri ar Di trib tio	RE PRID									
		High Te io	RE HT									
		E e tri Pro io	RE EP	0	0	0	0	0	0	0	0	0
		ighti g	RE C T									
		Tota POR	POR	1.0 0	1.0 0	1.0 0	1.0 0	1.0 0	1.0 0	1.0 0	1.0 0	1.0 0
		Tota POR	POR	0.0 0	0.00	0.00000	0.10	0.01 1	0.0	0.0 111	0.010 1	0.00
	0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
□D□	1	**ALLOCATED DIRECT ASSIGNMENTS**											
□D□	□	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**											
□D□	□												
□D□	□	**AVAILABLE**											
□D□	□	Re□ide□tia□	□RE□RE□	0	0	0	0	0	0	0	0	0	0
□D□	□	Re□ide□tia□Heati□g	□RE□RH	0	0	0	0	0	0	0	0	0	0
□D□	□	Ge□era□□er□□e	□RE□G□	0	0	0	0	0	0	0	0	0	0
□D□	□	Pri□ar□Di□trib□tio□	□RE□PRID	0	0	0	0	0	0	0	0	0	0
□D□	□	High Te□□io□	□RE□HT	0	0	0	0	0	0	0	0	0	0
□D□	10	E□e□tri□Pro□□□io□	□RE□EP	0	0	0	0	0	0	0	0	0	0
□D□	11	□ighti□g	□RE□□C□□T	0	0	0	0	0	0	0	0	0	0
□D□	1□												
□D□	1□												
□D□	1□												
□D□	1□	Tota□□□ai□ab□e	□RE□□□□I□	0	0	0	0	0	0	0	0	0	0
□D□	1□												
□D□	1□	Tota□□□ai□ab□e	□RE□□□□I□	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□D□	1□												
□D□	1□												
□D□	□0												
□D□	□1												
□D□	□□												
□D□	□□												
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□D□	□1												
□D□	□□												
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□D□	□□												
□D□	□□												
□D□	□0												
□D□	□1												
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□D□	□0												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
□D□	1	**ALLOCATED DIRECT ASSIGNMENTS**										
□D□	□	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**										
□D□	□											
□D□	□	**AVAILABLE**										
□D□	□	Re□ide□tia□	□RE□RE□	0	0	0	0	0	0	0	0	0
□D□	□	Re□ide□tia□Heati□g	□RE□RH	0	0	0	0	0	0	0	0	0
□D□	□	Ge□era□□er□□e	□RE□G□	0	0	0	0	0	0	0	0	0
□D□	□	Pri□ar□Di□trib□tio□	□RE□PRID	0	0	0	0	0	0	0	0	0
□D□	□	High Te□□io□	□RE□HT	0	0	0	0	0	0	0	0	0
□D□	10	E□e□tri□Pro□□□io□	□RE□EP	0	0	0	0	0	0	0	0	0
□D□	11	□ighti□g	□RE□□C□□T	0	0	0	0	0	0	0	0	0
□D□	1□											
□D□	1□											
□D□	1□											
□D□	1□	Tota□□□ai□ab□e	□RE□□□□I□	0	0	0	0	0	0	0	0	0
□D□	1□											
□D□	1□	Tota□□□ai□ab□e	□RE□□□□I□	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
□D□	1□											
□D□	1□											
□D□	□0											
□D□	□1											
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□D□	□0											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI	DEMDISSEC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
RR□	1	**DISTRIBUTION REVENUE REQUIREMENTS**											
RR□	□												
RR□	□	PRE□E□T R□TE□											
RR□	□	----------											
RR□	□	R□TE B□□E		□□□00□□□□	□□□1 □□1 □□	□□1 □□	□□□□□□1 □□	0	□□□01	□□□11□□□□	□□□□□0 □□	1□□□□□□□	0
RR□	□	□ET OPER I□C □PRE□E□T R□TE□□		□□□□□□□	□□□□□□□	□□	10□□□□□	0	□□0	□□□□□□□	1□□□□□0	□0□□□□	0
RR□	□	R□TE OF RET□R□ □PRE□ R□TE□□		□□□1□	□□□□□	□□□1□	□□□□□	11□□□0□	□□□□□	□□□□□	□□□□□	□□□□□	11□□□1□
RR□	□	RE□□TI□E R□TE OF RET□R□		1□00	1□00	1□00	1□00	1□00	1□00	1□00	1□00	1□00	1□00
RR□	□	□□□E□ RE□E□□E □PRE R□TE□□		1□□□□□1□□	□□1□□□□	□□□1□	□1□□□00	0	1□□□□	□□□□□□□	□□0□□□	□□□□1□□	0
RR□	10	RE□E□□E PRE□ R□TE□ □□□□ H		□0□0□□□	□0□0□□□	□0□000□	□0□01□0	□0□0000	□0□0000	□0□0□□□	□0□01□□	□0□00□□	□0□0000
RR□	11	RE□E□□E RE□ □IRED - □IMO□C□□T		□□□□1□	□□□□□□□	□0□□□	□□0□0□	□0□00	□0□0□	□□□□□□□	□□□□0□	□10□□□	□0□00
RR□	1□	□□□E□ RE□ RE□ □IRED □□□□		□□□□□1	□1□□□□	□0□1□	□10□□□	□0□00	□0□0□	□1□□□□	□11□1□	□□□□1	□0□00
RR□	1□												
RR□	1□	C□□IMED R□TE OF RET□R□											
RR□	1□	----------											
RR□	1□	C□□IMED R□TE OF RET□R□		□□□□□	□□□□□	□□□□□	□□□□□	□□□□1□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□0□
RR□	1□	RET□R□ RE□ FOR C□□IMED ROR		□0□□□□□	□□0□□□0	1□□	1□1□□□□	0	□□0	□1□□□00	□□□□1□□	10□□□□□	0
RR□	1□	□□□E□ RE□E□□E RE□ C□□IMED ROR - Di□trib□tio□		□0□□□□□□	1□□1□□0□□	□□□□0	□□□□□□□	0	1□□0□	1□□1□□□□	□0□□□□□	□□□□□□□	0
RR□	1□	RE□E□□E DEFICIE□C□ □□□E□ RE□		□□□□□□□	□□□□□00	11□	10□□□□□	0	□1□	□□□□□□□	□□□□□□□	□□□□□□□	0
RR□	□0	PERCE□T I□CRE□□E RE□ □IRED		□□□1□□	□□□□1□	1□□□□	1□□□□□	□□□0□□	□□□□□□	□□□□□□	□□□0□□	□□□□1□	□□□11□
RR□	□1	□□□□□□BOO□ED □□ H □□□E□		□□□□□□□0□□	□□□□□□□0□□	□□□□□□□0□□	□□□□□□□0□□	□□□□□□□0□□	□□□□□□□0□□	□□□□□□□0□□	□□□□□□□0□□	□□□□□□□0□□	□□□□□□□0□□
RR□	□□	□□□E□ RE□ RE□□IRED □□□□ H		□0□0□□□	□0□0□□□	□0□000□	□0□0□00	□0□0000	□0□0000	□0□0□□1	□0□0□□□	□0□00□□	□0□0000
RR□	□□	RE□E□□E DEFICIE□C□ □□□□ H		□0□01□□	□0□00□□	□0□0000	□0□00□0	□0□0000	□0□0000	□0□00□□	□0□00□□	□0□00□0	□0□0000

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RR□	1	**DISTRIBUTION REVENUE REQUIREMENTS**										
RR□	□											
RR□	□	PRE□E□T R□TE□										
RR□	□	----------										
RR□	□	R□TE B□□E		□00.□□□	□□1.□□	0	1□□□□1.□□	□□□□□□□	1□1.□□□	1□□□.0□	1.□□□	1.□□□
RR□	□	□ET OPER I□C □PRE□E□T R□TE□□		□0.□□□	□□	0	□□□□□□	11.□□□	□□10□	□□□□	□□□	1.□□1
RR□	□	R□TE OF RET□R□ □PRE□ R□TE□□		□□□0□	□□□1□	11.□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	10.10□
RR□	□	RE□□TI□E R□TE OF RET□R□		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
RR□	□	□□□E□ RE□E□□E □PRE R□TE□□		□□□□□□	□□□1□	0	□□□□□□	□□□0□□	□□□□□□	□0.□□□1	□□□□□	□1.□□□
RR□	10	RE□E□□E PRE□ R□TE□ □□□□ H		□0.00□0	□0.000□	□0.0000	□0.00□□	□0.000□	□0.001□	□0.00□□	□0.000□	□0.000□
RR□	11	RE□E□□E RE□□IRED - □IMO□C□□T		□□□□□	□0.□□□	□0.00	□1.□□□	□1.□□1	□□□□0	□□□□□	□1.□□1	□1.□□□
RR□	1□	□□□E□ RE□ RE□□IRED □□□□		□1.□□□	□0.1□	□0.00	□□□□□	□0.□□□	□0.□□□	□□□□□	□0.□□□	□0.□□□
RR□	1□											
RR□	1□	C□□IMED R□TE OF RET□R□										
RR□	1□	----------										
RR□	1□	C□□IMED R□TE OF RET□R□		□□□□□	□□□□□	□□□□0□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□	□□□□□
RR□	1□	RET□R□ RE□ FOR C□□IMED ROR		□□□□1□	1.□□	0	1.□□□□□	□0.□□□	10.□□0	1.□□□□	□□□	1.00□
RR□	1□	□□□E□ RE□E□□E RE□ C□□IMED ROR - Di□trib□tio□		110.□□□	□□□□0	0	□□□□□0□	□□□□□□	□□□□□□	□11.□0□	□□□.1□	□1.1□1
RR□	1□	RE□E□□E DEFICIE□C□ □□□E□ RE□		□□□0□□	11□	0	□□□□□□	1.□□1□	□□□□0	□□1.□□	□□□	□□□□□
RR□	□0	PERCE□T I□CRE□□E RE□□IRED		□0.0□□	1.□□□	□□□1.□□	□□□□□□	□□□1.□□	1.□0.□□	□□□□□	□01.□	-1.□□□
RR□	□1	□□□□□□BOO□ED □□ H □□□E□		□□□□□□0.□□	□□□□□□0.□□	□□□□□□0.□□	□□□□□□0.□□	□□□□□□0.□□	□□□□□□0.□□	□□□□□□0.□□	□□□□□□0.□□	□□□□□□0.□□
RR□	□□	□□□E□ RE□ RE□□IRED □□□□ H		□0.00□0	□0.000□	□0.0000	□0.00□□	□0.001□	□0.001□	□0.00□□	□0.000□	□0.000□
RR□	□□	RE□E□□E DEFICIE□C□ □□□□ H		□0.0010	□0.0000	□0.0000	□0.00□□	□0.000□	□0.000□	□0.000□	□0.0000	□□0.0000□

PECO Exhibit TJJ-4:

Unitized Functionally Classified Revenue Requirement

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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**									
	RATE OF RETURN									
	REVENUES REQUIRED									
	DEMAND COMPONENTS									
	DEM D PROD CTIO COMPO E T		0	0	0	0	0	0	0	0
	DEM D TR MI IO COMPO E T									1
	DEM D DI TRIB TIO COMPO E T									0
10	DEM D DI TRIB TIO PRIM R HT		0							
11	DEM D DI TRIB TIO PRIM R						011	0	0	
	DEM D DI TRIB TIO ECO D R		0	0	0	0	0	0	0	0
	DEM D DI TRIB TIO TR FORMER						0	0	0	
	ENERGY COMPONENTS									
	E ERG P R P R OTHER									
	CUSTOMER COMPONENTS									
	C TOMER DI TRIB TIO PRIM R		0	0	0	0	0	0	0	0
	C TOMER DI TRIB TIO ECO D R						0	0	0	
	I B E COMPO E T		0	0	0	0	0	0	0	0
0	C TOMER ER ICE I E TME T								0	0
1	C TOMER METER I E TME T						1		0	0
	C TOMER CCO T EXPE E		0							
	C TOMER ER ICE EXPE E								0	
	C TOMER OTHER								1	
	TOTAL COMPANY									
0	a M h a e Meter									
1	a M - Bi ed			0	0				1	0
	ber of C to er Bi		0				0			
	e er Mo th er C to er			0						
0										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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**									
	RATE OF RETURN									
	$/KWH									
	DEMAND COMPONENTS									
	DEM D PROD CTIO COMPO E T									
	DEM D TR MI IO COMPO E T									
	DEM D DI TRIB TIO COMPO E T									
10	DEM D DI TRIB TIO PRIM R HT									
11	DEM D DI TRIB TIO PRIM R									
1	DEM D DI TRIB TIO ECO D R									
1	DEM D DI TRIB TIO TR FORMER									
1	**ENERGY COMPONENTS**									
1	E ERG P R P R OTHER									
1	**CUSTOMER COMPONENTS**									
1	C TOMER DI TRIB TIO PRIM R									
1	C TOMER DI TRIB TIO ECO D R									
1	I B E COMPO E T									
0	C TOMER ER ICE I E TME T									
1	C TOMER METER I E TME T									
	C TOMER CCO T EXPE E									
	C TOMER ER ICE EXPE E									
	C TOMER OTHER									
	TOTAL COMPANY									
	$/KW									
	DEMAND COMPONENTS									
	DEM D PROD CTIO COMPO E T									
0	DEM D TR MI IO COMPO E T									
1	DEM D DI TRIB TIO COMPO E T									
	DEM D DI TRIB TIO PRIM R HT									
	DEM D DI TRIB TIO PRIM R									
	DEM D DI TRIB TIO ECO D R									
	$/MONTH/CUSTOMER									
	CUSTOMER COMPONENTS									
	C TOMER DI TRIB TIO PRIM R									
	C TOMER DI TRIB TIO ECO D R									
0	I B E COMPO E T									
1	C TOMER ER ICE I E TME T									
	C TOMER METER I E TME T									
	C TOMER CCO T EXPE E									
	C TOMER ER ICE EXPE E									
	C TOMER OTHER									
0										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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**									
	RATE OF RETURN									
	REVENUES REQUIRED									
	DEMAND COMPONENTS									
	DEM D PROD CTIO COMPO E T		0	0	0	0	0	0	0	0
	DEM D TR MI IO COMPO E T									1
	DEM D DI TRIB TIO COMPO E T									
10	DEM D DI TRIB TIO PRIM R HT									
11	DEM D DI TRIB TIO PRIM R							0	0	
	DEM D DI TRIB TIO ECO D R		0	0	0	0	0	0	0	0
	DEM D DI TRIB TIO TR FORMER						0	0	0	
	ENERGY COMPONENTS									
	E ERG P R P R OTHER									
	CUSTOMER COMPONENTS									
	C TOMER DI TRIB TIO PRIM R		0	0	0	0	0	0	0	0
	C TOMER DI TRIB TIO ECO D R						0	0	0	
	I B E COMPO E T		0	0	0	0	0	0	0	0
0	C TOMER ER ICE I E TME T								0	0
1	C TOMER METER I E TME T						1		0	0
	C TOMER CCO T EXPE E									
	C TOMER ER ICE EXPE E							0	0	
	C TOMER OTHER								1	
	TOTAL COMPANY									
										0
0	a M h a e Meter									
1	a M - Bi ed			0	0					0
	ber of C to er Bi									
0										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2025

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**									
	RATE OF RETURN									
	$/KWH									
	DEMAND COMPONENTS									
	DEMAND PRODUCTION COMPONENT									
	DEMAND TRANSMISSION COMPONENT									
	DEMAND DISTRIBUTION COMPONENT									
10	DEMAND DISTRIBUTION PRIMARY HT									
11	DEMAND DISTRIBUTION PRIMARY									
	DEMAND DISTRIBUTION ECONODAR									
	DEMAND DISTRIBUTION TRANSFORMER									
	ENERGY COMPONENTS									
	ENERGY PAR OTHER									
	CUSTOMER COMPONENTS									
	CUSTOMER DISTRIBUTION PRIMARY									
	CUSTOMER DISTRIBUTION ECONODAR									
	INSIDE WIRE COMPONENT									
0	CUSTOMER SERVICE INVESTMENT									
1	CUSTOMER METER INVESTMENT									
	CUSTOMER ACCOUNT EXPENSE									
	CUSTOMER SERVICE EXPENSE									
	CUSTOMER OTHER									
	TOTAL COMPANY									
	$/KW									
	DEMAND COMPONENTS									
	DEMAND PRODUCTION COMPONENT									
0	DEMAND TRANSMISSION COMPONENT									
1	DEMAND DISTRIBUTION COMPONENT									
	DEMAND DISTRIBUTION PRIMARY HT									
	DEMAND DISTRIBUTION PRIMARY									
	DEMAND DISTRIBUTION ECONODAR									
	$/MONTH/CUSTOMER									
	CUSTOMER COMPONENTS									
	CUSTOMER DISTRIBUTION PRIMARY									
	CUSTOMER DISTRIBUTION ECONODAR									
0	INSIDE WIRE COMPONENT									
1	CUSTOMER SERVICE INVESTMENT									
	CUSTOMER METER INVESTMENT									
	CUSTOMER ACCOUNT EXPENSE									
	CUSTOMER SERVICE EXPENSE									
	CUSTOMER OTHER									
0										

PECO Exhibit TJJ-5:

Customer-Related Revenue Requirement and Customer Charge

Customer-Related Revenue Requirement and Customer Charge

Line	Description	Residential	Residential Heating	Total Residential	General Service	Primary Distribution	High Tension
1	Customer Services Investment ($000)	$ 22,913	$ 3,483	$ 26,397	$ 15,767	$ 38	$ 274
2	Customer Meter Investment ($000)	39,209	6,021	45,230	7,931	198	2,506
3	Customer Accounts ($000)	156,950	24,836	181,786	17,591	1,162	9,942
4	Customer Services ($000)	24,077	3,693	27,770	1,311	9	352
5	Total Revenue Requirement ($000)	$ 243,150	$ 38,033	$ 281,183	$ 42,600	$ 1,407	$ 13,074
6	Number of Customer Bills	16,065,289	2,452,036	18,517,325	1,878,765	4,608	32,712
7	$/Month/Customer (Line 5/Line 6*1000)	$ 15.14	$ 15.51	$ 15.18	$ 22.67	$ 305.40	$ 399.68

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 TJJ-4, page 3, lines 20 to 23.

PECO Exhibit TJJ-6:

Night Service Rider - Related Costs

Night Service Rider

Line	Description	FERC Account	Lines @ PECO Exhibits TJJ-2 and TJJ-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	1,005,841	47%	27,992	49%	644,667	44%	31,763	45%
2	Total Distribution Plant		RBP45	$ 2,162,398		$ 57,577		$ 1,456,446		$ 70,969	
3	NS Related Distribution O&M	593,594	E32, 33	$ 45,264	55%	$ 1,465	59%	$ 30,878	53%	$ 1,521	54%
4	Total Distribution Plant O&M Less A&G		E40	$ 82,598		$ 2,498		$ 58,083		$ 2,839	
5	Customer Accounts O&M	901-910,912,916	E59,67,69	$ 14,367		$ 656		$ 6,169		$ 53	
6	Total Dist. O&M + Customer Account			$ 96,965	47%	$ 3,154	46%	$ 64,252	48%	$ 2,892	53%
7	Total Distribution Revenue @ 7.98%		S69	$ 363,869		$ 10,921		$ 248,725		$ 11,645	
8	Total Distribution Operation Expense Less Depr Less Fed/State Taxes		S57,59,60	$ 153,580		$ 4,962		$ 103,048		$ 4,681	
9	NS Related Operation Expense			$ 71,692		$ 2,306		$ 49,523		$ 2,463	
10	Capital Related Costs @ 7.98%			$ 210,288		$ 5,958		$ 145,677		$ 6,963	
11	NS Related Capital Cost @ 7.98%			$ 97,816		$ 2,897		$ 64,481		$ 3,116	
12	NS Related Capital Plus Expense			$ 169,508		$ 5,202		$ 114,004		$ 5,579	
13	NCP Demand (MW)		AF21	1,818,882		67,759		2,416,494		119,063	
14	Monthly NS Cost ($/kW)			$ 7.77		$ 6.40		$ 3.93		$ 3.91	

PECO Exhibit TJJ-7:

Development of External Allocation Factors

Table of External Allocators

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External Allocator Values by Class

Schedule-1

Line	Units	Allocator Names	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	MWh	Energy @ Meter	36,395,096	11,367,081	2,892,680	7,546,792	290,810	13,682,696	444,680	170,358
2	MWh	Energy @ Generation	39,246,230	12,539,027	3,190,915	8,324,866	315,267	14,225,899	462,334	187,922
3	MWh	Energy @ Generation-CI	22,866,032			8,324,866	315,267	14,225,899		
4	MW	Demand Transmission (1CP)	8,162,912	3,388,691	478,686	1,794,443	65,195	2,357,772	72,240	5,886
5	MW	Demand Distribution Primary High Tension (NCP)	9,253,340	3,601,870	1,180,290	1,818,882	67,759	2,416,494	119,063	48,981
6	MW	Demand Distribution Primary (NCP)	6,717,782	3,601,870	1,180,290	1,818,882	67,759	-	-	48,981
7	MW	Demand Distribution Secondary (NCP)	6,650,023	3,601,870	1,180,290	1,818,882	-	-	-	48,981
8	KW	Billed Capacity	59,052,687	0	0	24,940,829	742,756	31,672,232	1,696,871	0
9	#	Bills	20,589,335	16,065,289	2,452,036	1,878,765	4,608	32,712	465	155,460
10	#	Customers	1,715,778	1,338,774	204,336	156,564	384	2,726	39	12,955
11	#	Customers-LCI	3,110				384	2,726		
12	#	Customers-Res	1,543,110	1,338,774	204,336					
13	#	Customers-Excl Ind	1,699,674	1,338,774	204,336	156,564				
14	#	Customers-CI	189,660			156,564	384	32,712		
15	#	Location Secondary	1,755,131	1,338,774	204,336	156,564				55,457
16	$000	Services Cost	7,924,275	4,254,640	649,383	2,961,426	7,263	51,563	-	-
17	$000	Meters Cost	369,993	258,902	39,678	53,038	1,334	16,842	199	-
18	$000	Purchased Power	1,071,200	689,404	180,937	147,983	1,083	50,940	-	854
19	$000	Write-Offs	107,322	80,004	17,968	8,228	40	1,073	-	9
20	%	Customer Records and Collection Expenses (Acct903)	100.00%	73.82%	11.65%	8.37%	0.59%	4.99%	0.05%	0.54%
21	%	Customer Assistance Expenses (Acct908)	100.00%	83.47%	12.74%	3.35%	0.01%	0.25%	0.00%	0.20%
22	%	Demonstrating and Selling Expense / Miscellaneous Sales Expense (Accts 912/916)	100.00%	0.00%	0.00%	36.41%	1.38%	62.21%	0.00%	0.00%
23	%	AR Over60-Day	100.00%	68.10%	13.07%	9.80%	0.36%	8.35%	0.33%	0.00%
24	%	Customer Deposit	100.00%	30.24%	6.79%	53.91%	0.32%	8.73%	0.00%	0.00%
25	%	Purchase of Receivables	100.00%	26.60%	6.77%	33.84%	0.67%	31.67%	0.00%	0.45%
26	%	Lighting	100.00%							100%
27	$000	Transit Charging - GS	413			413				
28	$000	Transit Charging - PD/HT	(413)				(22)	(390)		

External Allocator Values by Function

Schedule-2

Line	Accounts/Functional Allocation Factors	Total	Primary-HT	Primary	Secondary
1	Overhead Conductors & Devices (Acct 365)	100.00%	46.24%	25.93%	27.83%
2	Underground Conductors & Devices (Acct 367)	100.00%	59.83%	15.99%	24.19%
3					

Schedule-3

Conductors - Functional
As of December 31, 1999

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

Schedule-4

Conductors - Primary
As of December 31, 2023

Line	System Voltage	Class	Overhead Conductor Wire_Miles	Underground Conductor Wire_Miles
1	2.4	Primary	98	169
2	4	Primary	10,543	3,422
3	13	HT	9,452	8,097
4	34	HT	9,525	5,341
5			29,618	17,030
6				
7		Primary	10,641	3,591
8		HT	18,977	13,439
9			29,618	17,030
10				
11		Primary	35.9%	21.1%
12		HT	64.1%	78.9%
13			100.0%	100.0%
14				

Service Costs

Schedule-5

Line	Rate Class	Customer Numbers	Average Services Cost	Total Services Cost	Ratio
1	Residential	1,338,774	$ 3,178	$ 4,254,639,886	53.7%
2	Residential Heating	204,336	$ 3,178	$ 649,383,286	8.2%
3	General Service	156,564	$ 18,915	$ 2,961,426,162	37.4%
4	Primary Distribution	384	$ 18,915	$ 7,263,416	0.1%
5	High Tension	2,726	$ 18,915	$ 51,562,688	0.7%
6	Electric Propulsion	39			
7	Lighting	12,955			
8		1,715,778		$ 7,924,275,438	100%

Meter Costs (a)

Schedule-6

Line	Rate Class	Average Cost (b)
1	Residential	$ 193
2	Residential Heating	$ 194
3	General Service	$ 339
4	Primary Distribution	$ 3,474
5	High Tension	$ 6,178
6	Electric Propulsion	$ 5,124
7	Lighting	
8	Total	

(a) Meter counts as of December 2023
(b) Includes cost of material and labor

Customer Deposits

Schedule-7

Thirteen Months Ended December 31, 2023

Line	Activity	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Customer Deposit	100.0%	30.2%	6.8%	53.9%	0.3%	8.7%	0.0%	0.0%
2		100.0%	30.2%	6.8%	53.9%	0.3%	8.7%	0.0%	0.0%

Schedule-8

Customer Records and Collection Expenses (Account 903)
For Year 2022

Line	Activity	Total	Allocator	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Billing	20,235,725	Bills	20,235,725	15,789,377	2,409,924	1,846,498	4,529	32,150	457	152,790
2	CAP Rates	2,783,475	Customers-Res	2,783,475	2,414,891	368,584	-	-	-	-	-
3	Recoveries	5,449,352	AR Over60-Day	5,449,352	3,710,753	712,324	533,844	19,515	454,904	18,012	-
4	Call Center	18,008,912	Customers	18,008,912	14,051,856	2,144,727	1,643,303	4,030	28,612	407	135,976
5	C&MS	15,007,627	Customers	15,007,627	11,710,036	1,787,296	1,369,437	3,359	23,844	339	113,315
6	ESO Activities	3,414,119	Customers-LCI	3,414,119	-	-	-	421,550	2,992,568	-	-
7	Financial Calls	6,154,018	AR Over60-Day	6,154,018	4,190,597	804,436	602,877	22,038	513,729	20,341	-
8	Low Income	1,413,994	Customers-Res	1,413,994	1,226,755	187,239	-	-	-	-	-
9	Field Vendor	3,438,411	Customers	3,438,411	2,682,897	409,489	313,753	770	5,463	78	25,962
10	Care Center	4,066,388	Customers-Excl Ind	4,066,388	3,202,952	488,865	374,571	-	-	-	-
11	Other	1,265,249	Customers	1,265,249	987,239	150,682	115,453	283	2,010	29	9,553
12		81,237,269		81,237,269	59,967,354	9,463,565	6,799,737	476,074	4,053,281	39,663	437,597
13	**Acct903 Allocator**			**100.00%**	**73.82%**	**11.65%**	**8.37%**	**0.59%**	**4.99%**	**0.05%**	**0.54%**

Schedule-9

Customer Assistance Expenses (Account 908)
For Year 2022

Line	Activity	Total	Allocator	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Residential Marketing	1,295,662	Customers-Res	1,295,662	1,124,093	171,570	-	-	-	-	-
2	C&I Marketing	141,418	Customers-CI	141,418	-	-	116,740	286	24,391	-	-
3	Marketing - General	2,394,659	Customers	2,394,659	1,868,486	285,186	218,511	536	3,805	54	18,081
4	LIURP	7,410,644	Customers-Res	7,410,644	6,429,338	981,306	-	-	-	-	-
5	Other	706,152	Customers	706,152	550,991	84,097	64,436	158	1,122	16	5,332
6		11,948,536		11,948,536	9,972,908	1,522,159	399,687	980	29,318	70	23,413
7	**Acct908 Allocator**			**100.00%**	**83.47%**	**12.74%**	**3.35%**	**0.01%**	**0.25%**	**0.00%**	**0.20%**

Schedule-10

Demonstrating and Selling Expense / Miscellaneous Sales Expense
For Year 2022

Line	Activity	Total	Allocator	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	C&I Expense	435,787	Energy @ Generation-CI	435,787	-	-	158,657	6,008	271,121	-	-
2		435,787		435,787	-	-	158,657	6,008	271,121	-	-
3	**Acct912 and 916 Allocator**			**100.00%**	**0.00%**	**0.00%**	**36.41%**	**1.38%**	**62.21%**	**0.00%**	**0.00%**

Write-Offs

Schedule-11 **Net Write-Offs from 2021 to 2023**

Line	Rate Class	Net Write-Offs
1	Residential	$ 80,004,391
2	Residential Heating	17,967,999
3	General Service	8,227,944
4	Primary Distribution	39,559
5	High Tension	1,073,078
6	Electric Propulsion	-
7	Lighting	8,816
8		$ 107,321,787

Schedule-12

Accounts Receivable Over 60-Day
January 2022 to December 2022

Line	Rate Class	Average Over 60-Day	Over 60-Day Allocator	Residential	% Residential Revenue	LC&I Revenue	% LC&I Revenue
1	Residential	$ 79,051,979	68.1%	$ 927,169,372	83.9%		
2	Residential Heating	15,174,984	13.1%	177,981,386	16.1%		
3	General Service	11,372,743	9.8%				
4	Primary Distribution	415,727	0.4%			$ 7,647,292	4.0%
5	High Tension	9,691,047	8.3%			178,266,579	92.4%
6	Electric Propulsion	383,724	0.3%			7,058,589	3.7%
7	Lighting	0	0.0%				
8	**Total**	$ 116,090,204	100.0%	$ 1,105,150,758	100.0%	$ 192,972,460	100.0%

Purchase of Receivables
For Test Year 2025

Schedule-13

Line		Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Sales (MWh)	36,395,096	11,367,081	2,892,680	7,546,792	290,810	13,682,696	444,680	170,358
2	% R and RH		79.7%	20.3%					
3	% PD and HT					2.1%	97.9%		
4	Total Amount ($)	$ 1,082,504,054	287,930,069	73,272,058	366,300,015	7,287,335	342,871,545	-	4,843,032
	POR Allocator	**100%**	**26.60%**	**6.77%**	**33.84%**	**0.67%**	**31.67%**	**0.00%**	**0.45%**

Demand Allocator

Schedule-14

October 2022 to September 2023

Line	Demand Allocator	Total MWs	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	1CP	8,162,912	3,388,691	478,686	1,794,443	65,195	2,357,772	72,240	5,886
2	NCP- Primary HT	9,253,340	3,601,870	1,180,290	1,818,882	67,759	2,416,494	119,063	48,981
3	NCP- Primary	6,717,782	3,601,870	1,180,290	1,818,882	67,759	-	-	48,981
4	NCP- Secondary	6,650,023	3,601,870	1,180,290	1,818,882	-	-	-	48,981
5									

Schedule-15

Energy Allocator
FPFTY 2025

Line	Rate Class	Function	MWh Deliveries at Meter	MWh Deliveries at Generation
1	Residential	Secondary	11,367,081	12,539,027
2	Residential Heating	Secondary	2,892,680	3,190,915
3	General Service	Secondary	7,546,792	8,324,866
4	Primary Distribution	Primary	290,810	315,267
5	High Tension	HT	13,682,696	14,225,899
6	Electric Propulsion	HT	444,680	462,334
7	Lighting	Secondary	170,358	187,922
8	**Total**		36,395,096	39,246,230

Schedule-16

Transit Charging Allocator
FPFTY 2025

Line		Allocation Basis	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Prior Rate Case	SREVPDHT (prior case)	$ (1,000,000)				$ (46,534)	$ (953,466)		
2	Current Rate Case	Customers - LCI	$ 1,000,000			$ 825,498	$ 2,025	$ 172,477		
3	Variance		$ -	$ -	$ -	$ 825,498	$ (44,509)	$ (780,989)	-	-
4	Annual with 2-year Amort.		$ -	$ -	$ -	$ 412,749	$ (22,254)	$ (390,495)	-	-
5	Allocation Factor					100%	-5.4%	-94.6%		

PECO Exhibit TJJ-8:

Development of Unbundled Cash Working Capital Rate for the Generation Supply Adjustment

PECO Energy Company
Estimated Cash Working Capital Rate for the GSA
To be Effective January 1, 2025
('000s)

1	CWC Rate Base Allocated to Purchased Power[(1)]	$	45,182
2	Rate of Return[(2)]		7.980%
3	Return on CWC Rate Base	$	3,606
4	Income Taxes on Equity portion of Return[(3)]	$	993
5	Gross Receipts Tax @ 5.9%	$	288
6	Total Revenue Requirement	$	4,887
7	Default Service Sales (MWH)		13,939,859
8	Estimated Rate per kWh	$	0.00035

Notes:
1 PECO Exhibit TJJ-1, Line 34
2 PECO Exhibit MJT-1, Schedule 1
3 PECO Exhibit TJJ-1, Line 80

PECO Exhibit TJJ-9:

Development of Unbundled Cash Working Capital Rate for the Transmission Service Charge

PECO Energy Company
Estimated Cash Working Capital Rate for the TSC
To be Effective January 1, 2025
('000s)

1	CWC Rate Base Allocated to Transmission TSC [1]	$	9,918
2	Rate of Return[2]		7.980%
3	Return on CWC Rate Base	$	791
4	Income Taxes on Equity portion of Return[3]	$	218
5	Gross Receipts Tax @ 5.9%	$	63
6	Total Revenue Requirement	$	1,073
7	Default Service Peak Forecast (MW)		3,916
8	Estimated Rate per MW-year	$	274

Notes:
1 PECO Exhibit TJJ-1, Line 43
2 PECO Exhibit MJT-1, Schedule 1
3 PECO Exhibit TJJ-1, Line 92

PECO ENERGY COMPANY
STATEMENT NO. 6-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

REBUTTAL TESTIMONY

WITNESS: TAMARA J. JAMISON

SUBJECT: CLASS COST OF SERVICE STUDY AND CUSTOMER CHARGE

DATED: JULY 16, 2024

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III. RESIDENTIAL CUSTOMER CHARGE 9

IV. CONCLUSION 11

REBUTTAL TESTIMONY
OF
TAMARA J. JAMISON

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Tamara J. Jamison. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Manager, Revenue Policy. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, PA 19103.

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

A. Yes. I submitted direct testimony marked as PECO Statement No. 6. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to:

(1) Office of Consumer Advocate ("OCA") witness Clarence Johnson regarding the unbundled, fully allocated class cost-of-service study ("COSS") I performed on the Company's behalf and the residential customer charge calculation;

(2) Office of Small Business Advocate ("OSBA") witness Kevin C. Higgins regarding PECO's allocation of line transformer costs in the COSS;

(3) Philadelphia Area Industrial Energy Users Group ("PAIEUG") witness Billie S. LaConte regarding non-coincident peak ("NCP") data driving relative rates of return in the COSS; and

(4) Southeastern Pennsylvania Transportation Authority ("SEPTA") witness James L. Crist regarding the use of NCP as a demand allocator in the COSS.

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

A. Yes, I have prepared the following exhibits:

PECO Exhibit TJJ-10	OCA's response to PECO-OCA-II-8
PECO Exhibit TJJ-11	FERC Accounts 364-367 – Allocation between customer and demand by other Pennsylvania electric distribution utilities
PECO Exhibit TJJ-12	Comparison of Non-Coincident Peaks by class

II. THE COMPANY'S CLASS COST-OF-SERVICE STUDY

5. Q. What issues raised by OCA witness Johnson concerning the COSS will you address?

A. I will address the following issues raised by Mr. Johnson concerning the COSS: (1) the Company's customer-based allocation of secondary voltage distribution plant; and (2) the allocation of "Other Revenues."

6. Q. Mr. Johnson contends that it is more appropriate to allocate secondary voltage distribution plant, including secondary poles, overhead conductors, and underground conductors/conduit, based on demand only. Do you concur with his analysis?

A. No. Mr. Johnson suggests that his proposal for a purely demand-related allocation is the prevailing regulatory treatment for secondary distribution plant (*see* OCA St. No. 3, p. 12). The Pennsylvania Public Utility Commission ("Commission") has previously rejected the OCA's contention that upstream secondary distribution plant should be classified as 100% demand related.[1]

[1] *See Pa. P.U.C. v. UGI Utils., Inc. – Elec. Div.*, R-2017-2640058 (Opinion and Order entered Oct. 4, 2018) ("*UGI Electric 2018*"), pp. 156-60.

To support his claim, Mr. Johnson also references an electric utility cost allocation manual that describes the "basic customer method" (i.e., classifying all wires, poles, and transformers as demand-related) as a "general approach . . . used by more than 30 states" (*see* OCA St. No. 3, p. 12). However, Mr. Johnson was not able to provide details on which specific utilities within those 30 states, other than Texas, actually use the basic customer method, or whether those utilities were ordered to do so by their respective state regulatory bodies.[2] Additionally, Mr. Johnson ignores that there is a diversity of opinion on the regulatory treatment for secondary distribution plant. And, while the basic customer method may be used in some states, it is inconsistent with Commission practice and not the prevailing approach in this jurisdiction. Indeed, utilities in Pennsylvania allocated approximately 48% to 89% of secondary distribution plant on a customer basis.[3] This range is more reflective of the regulatory treatment for secondary distribution plant in the region and consistent with published guidance identifying customer costs as including "meters, meter reading, billing, *and some portion of the distribution system.*"[4]

Mr. Johnson's conclusion also ignores the principal cost drivers for some secondary distribution plant. For example, the principal cost driver for conductors is the labor cost component of installation costs, which correlates

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2 *See* PECO Exhibit TJJ-10 (OCA Response PECO-OCA-II-8).

3 Pennsylvania utilities also allocated approximately 0% to 92% of primary distribution plant on a customer basis. PECO, on the other hand, allocates primary distribution plant based on demand only. *See* PECO Exhibit TJJ-11.

4 Cawley, James H. and Kennard, Norman J., *A Guide to Utility Ratemaking Before the Pennsylvania Public Utility Commission*, p. 144 (2018) (emphasis added).

much more closely with the length of the installed conductors and, therefore, to the number of customer locations that those conductors connect to the primary voltage system.

7. Q. Mr. Johnson also avers that distribution plant is correlated with load density but is not significantly impacted by the number of secondary voltage customers on the system. Do you agree?

A. No. Mr. Johnson's premise regarding load density is also incorrect. Just because secondary voltage distribution facilities may be used by more customers in a densely populated area as compared to a less densely populated area does not alter the fact that those facilities are customer-related. The distribution system has to be built to serve all customers without regard to their spatial distribution, and the fact remains that, because facilities are built to physically connect all secondary voltage customers to each other and to the primary voltage system, the costs of those facilities are customer-related.

Mr. Johnson contends that potential economies of scale may reduce the cost of building and maintaining distribution facilities in more densely populated areas. However, there is no evidence that his hypothesis is correct in real-world conditions. Moreover, even if the economies of scale Mr. Johnson alleges did exist, they would not demonstrate that there is a tighter correlation (or any correlation at all) between the cost of secondary distribution facilities and demand.

PECO must install facilities to physically connect all secondary voltage

distribution customers, and it incurs the costs to do so, notwithstanding the level of demand those facilities carry.

Finally, Mr. Johnson attempts to criticize PECO's allocation of secondary voltage facilities based on a flawed comparison to the minimum system concept. Mr. Johnson does so by referencing an excerpt by Dr. James Bonbright that ostensibly highlights shortcomings in the minimum-system approach related to the identification of customer-related costs of the distribution system. The comparison Mr. Johnson attempts to draw is irrelevant because PECO does not utilize a minimum-system approach. Therefore, Mr. Johnson's attempt to assign the flaws inherent in the minimum-system concept to PECO's allocation approach for secondary voltage facilities is misguided and should be disregarded completely. Even so, Dr. Bonbright's analysis does not "reveal similar flaws" in PECO's approach, as Mr. Johnson claims. To the contrary, Dr. Bonbright's conclusions undermine Mr. Johnson's argument. Mr. Johnson overlooks Dr. Bonbright's advice that excluding the minimum system component from demand-related costs "stands on much firmer ground."[5] Mr. Johnson's attempt to ascribe shortcomings in the minimum-system study to PECO's allocation approach is inappropriate for the reasons discussed above.

In summary, I believe that cost causation and related guidance from the Commission regarding some part of the distribution plant being classified as customer-related as described previously supports PECO's current cost

[5] James Bonbright et al., *Principles of Public Utility Rates*, pp. 491-92 (1988 ed.).

classification for both primary and secondary facilities in FERC accounts 364-367.

8. Q. Mr. Johnson proposes that two components of "Other Revenues," namely solar application fees and theft of service revenues, should be allocated to customer classes based on a customer basis instead of a distribution plant basis. Please respond.

A. I have reviewed Mr. Johnson's proposal and believe it is reasonable to use the customer allocator instead of the distribution plant allocator. The effect of this change would be to reallocate approximately $300,000 in "Other Revenue" to Residential ("R") and Residential Heating ("RH") customers.

9. Q. OSBA witness Higgins suggests that PECO incorporate a customer component in the allocation of transformer costs. Why is a purely demand-related allocation of those costs appropriate?

A. It is reasonable to allocate line transformers based on demand, as all customers are not created equal. The average demand for a rate General Service ("GS") customer is higher than for a rate R or rate RH customer. As such, rate GS customers frequently require larger kilovolt-amps and three-phase transformers, which have higher costs than transformers supplying typical rate R and rate RH customers.

10. Q. What issues raised by PAIEUG witness LaConte concerning cost-of-service will you address?

A. Ms. LaConte posits that the COSS results may not be representative of the cost to

serve each customer class. Ms. LaConte's basis for this conclusion is an observed change in the relative rate of return ("RROR"), going back to PECO's COSS results since 2010. Ms. LaConte compares the historical NCP load factor data from PECO's last two rate cases and suggests that PECO may be relying on "anomalous data" to determine its proposed rates for the fully projected future test year.

11. Q. Do you agree with Ms. LaConte's conclusion?

A. No. While Ms. LaConte is correct that NCP load factors have changed since prior rate cases, those values are not "anomalous." First, NCP data is not estimated, but rather is based on actual system data. Additionally, as shown in PECO Exhibit TJJ-12, NCPs used in the COSS in this case deviate from average NCPs for the October to September periods over the last 10 years by less than 1% for all customer classes and are closer to 10-year averages overall than the NCPs used in PECO's 2021 and 2018 electric rate case COSSs. Lastly, the approach of calculating demand allocations based on the NCPs of each class from the October to September period prior to the filing of a rate case has been used consistently in PECO's COSSs since 2018, and the use of stable methods in the COSS is a primary goal for setting allocation factors in conformance with the guiding principles for performing a COSS, as was discussed in my direct testimony beginning on page 7.

12. Q. What issues raised by SEPTA witness Crist concerning cost-of-service will you address?

A. Mr. Crist contends that the Demand Distribution Primary High Tension allocation

factor used in the COSS over-allocates costs to SEPTA through its two largest High Tension ("HT") and Electric Propulsion ("EP") accounts, which represent approximately 95% of SEPTA's electric use. Mr. Crist states that because the Demand Distribution Primary High Tension is based on NCP and not coincident peak demand, PECO's proposed cost allocation is inconsistent with cost allocation principles. As a result, Mr. Crist recommends that allocations to rate HT and rate EP should be reduced to no greater than the overall percentage increase that PECO is ultimately granted.

13. Q. Do you agree with Mr. Crist?

A. No. PECO properly used the NCP to allocate demand-related distribution costs. Load diversity affects system design and, therefore, consistent with cost-causation principles, it also influences how costs are allocated among customer classes. Distribution facilities serve load that is much more localized than the loads served at the bulk transmission level, which reflect the totality of energy moving on the system. As a result, distribution facilities must be sized to meet maximum demands that can be, and often are, imposed on those facilities at any time of the year, not just at the time of the system coincident peak. This characteristic of the distribution system and the loads it carries warrants the use of NCP demand to allocate demand-related costs.

Additionally, the use of NCP as a demand allocator aligns with the approach of other Pennsylvania utilities and has been used consistently in PECO's COSSes since 2010.

III. RESIDENTIAL CUSTOMER CHARGE

14. Q. Please summarize OCA witness Johnson's position on PECO's residential customer charge.

A. Mr. Johnson disagrees with PECO's 36% increase in the monthly residential customer charge. Mr. Johnson claims that the customer charge is above a basic customer charge benchmark and an excessive customer charge is contrary to the goal of promoting energy conservation.

15. Q. Do you agree with Mr. Johnson?

A. No. The costs included in PECO's proposed customer charge are consistent with the Commission's guidance in a 2012 PPL Electric Utilities Corp. ("PPL") proceeding and a 2004 Aqua Pennsylvania ("Aqua") proceeding.[6] Those cases support the recovery of both direct and certain indirect customer costs and reflect the Commission's current policy regarding customer charges. PECO's proposed customer charge is consistent with that guidance.

In contrast, Mr. Johnson's conclusions are based on superseded Commission policy that, prior to the Commission's entry of final orders in the *Aqua 2022*, *UGI Electric 2018*, *PPL 2012* and *Aqua 2004* cases, limited the customer charge to a narrower subset of direct costs.[7]

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[6] *Pa. P.U.C. v. PPL Elec. Utils. Corp*., Docket No. R-2012-2290597 (Opinion and Order entered Dec. 28, 2012) ("*PPL 2012*"); *Pa. P.U.C. v. Aqua Pa., Inc*., Docket No. R-00038805 (Opinion and Order entered Aug. 5, 2004) ("*Aqua 2004*"); *see also UGI Electric 2018*, pp. 173-76 (approving proposed increase in residential customer charge from $5.50 to $14.00 per month that was supported by a customer cost analysis consistent with the PUC's guidance in *PPL 2012* and *Aqua 2004*); *Pa. P.U.C. v. Aqua Pa., Inc*., Docket No. R-2021-3027385 (Opinion and Order entered May 16, 2022), pp. 268-69 ("*Aqua 2022*").

[7] OCA St. No. 3, p. 28 n.19. Of the decisions cited by Mr. Johnson, only one pertains to an electric utility, and it dates from 1990. The other two decisions that Mr. Johnson cited (both involving gas utilities) also predate the *PPL 2012* decision.

16. Q. Mr. Johnson has proposed maintaining the residential customer charge of $10.50 because he believes that PECO's proposed customer charge is too high and reflects costs that are not appropriately included in a customer charge that is limited to recovering only "direct" customer costs. Have you reviewed Mr. Johnson's analysis of the customer charge for reasonableness, and do you believe it is appropriate?

A. I have reviewed the analysis, and in addition to finding multiple instances where I disagree with the numbers utilized in his calculation, as well as the methodology employed not specifically discussed in Mr. Johnson's direct testimony (such as the elimination of costs from certain customer-related call center calls for emergencies), I conclude that Mr. Johnson, relying on superseded Commission policy, has failed to include all the costs that are permitted by the *Aqua 2022*, *UGI Electric 2018*, *PPL 2012* and *Aqua 2004* decisions.

Mr. Johnson proposes to exclude uncollectible expense and customer service and sales expense (FERC Accounts 908-916), which he contends are indirect costs largely unrelated to billing. However, all these costs are directly related to serving customers and vary in proportion to the number of customers. For example, the inclusion of some level of uncollectible expense is appropriate because not every customer pays his or her bill. As new customers are likely to have the same payment pattern, on average, as existing customers, there will be additional uncollectible accounts expense that is appropriately reflected in the customer charge. Moreover, the addition of new customers increases calls to the PECO call center and inquiries regarding problems with bill payment, for which

collection-related services are needed. Each customer service function, such as the call center, credit and collections, and billing functions, requires computers and appropriate IT support. In addition, Account 908 consists of customer assistance expense, and the addition of customers drives an increase in the kinds of customer assistance recorded in this account.

These are all appropriate inclusions in the customer charge and well within the allowable parameters of the Commission's current policy defining the kinds of costs that properly may be reflected in a customer charge.

IV. CONCLUSION

17. Q. Does this complete your rebuttal testimony at this time?

A. Yes. It does.

PECO Energy Company, R-2024-3046931 (Electric)

PECO Interrogatories to the Office of Consumer Advocate
Set II

PECO-OCA-II-8. Refer to OCA Statement No. 3, page 12. Please provide a list of utility companies known to Mr. Johnson who use the "basic customer method" described in the electric utility cost allocation manual referenced in footnote 7 and whether each utility opted to use this method or was ordered to do so by their Commission.

Response:

The cited Regulatory Assistance Project (RAP) manual specifically referenced the states of Arkansas, California, Colorado, Illinois, Iowa, Massachusetts, Texas, and Washington, as stated on page 12 of OCA Statement No 3. As noted in the footnotes at page 145 of the 2020 RAP Electric Utility Cost Allocation Manual, the basic customer method was used by the identified states based upon administrative rules and/or Commission rate case decisions. Mr. Johnson has not performed independent research to identify the states or utilities which use the method. However, he is aware of specific instances.

Mr. Johnson has extensive experience with the Texas jurisdiction and is aware that all eight investor owned electric utilities in the state currently use this method for classifying distribution costs.[1] With the initiation of retail competition in 2001, the Texas PUC entered a generic customer classification and rate design order for transmission-distribution utilities. Although the order did not use the term "basic customer method," it adopted a classification consistent with that approach. The only utility which did not adopt that method, Center Point Energy, requested a customer classification of transformers in its 2010 rate case. The Texas Commission denied the request and adopted distribution classification consistent with the basic customer method.

Mr. Johnson testified in the Baltimore Gas & Electric Co. (BGE) 2019 rate case in Maryland. BGE, which is an Exelon company (like PECO) classified electric distribution facilities similar to the basic customer method described on page 12 of OCA Statement 3. To the best of Mr. Johnson's knowledge, BGE's classification continued the methodology previously approved by the Maryland PSC.

Dated: July 1, 2024

Sponsored by: Clarence Johnson

[1] Oncor Electric Delivery Co., Center Point Electric Energy Co., Texas New Mexico Electric Co., AEP Texas, Southwestern Electric Power Co., Southwestern Public Service Co., El Paso Electric Co., Sharyland Electric Utility Co.

Primary & Secondary Allocation of Distribution Plant: FERC Accounts 364-367

Utility	Primary Demand	Primary Customer	Secondary Demand	Secondary Customer	Reference: Docket #
Duquesne - 2021	100%	0%	17%	83%	R-2021-3024750
Duquesne - 2024*	100%	0%	17%	83%	R-2024-3046523
Met-Ed	23%	77%	21%	79%	R-2016-2537349
Pennelec	21%	79%	21%	79%	R-2016-2537352
Penn Power	12%	88%	16%	84%	R-2016-2537355
West Penn Power	12%	88%	14%	86%	R-2016-2537359
First Energy - Met-Ed*	15%	85%	14%	86%	R-2024-3047068
First Energy - Penelec*	16%	84%	15%	85%	R-2024-3047068
First Energy - Penn Power*	9%	91%	11%	89%	R-2024-3047068
First Energy - West Penn*	8%	92%	12%	88%	R-2024-3047068
PPL	41%	59%	35%	65%	R-2015-2469275
UGI -2021	58%	42%	52%	48%	R-2021-3023618
UGI - 2022	48%	52%	33%	67%	R-2022-3037368

Note: Percentage (%) based off of weighted average of FERC accounts' 364-367 allocation factors

* Cases pending before the Commission

	Peak (KW) by Rate Class - NCP (From Attachment SDR-COS-1(b))						
Date	**R**	**RH**	**GS**	**PD**	**HT**	**EP**	**Lighting**
Oct-13	2,058,762	456,694	1,529,273	96,854	2,313,649	139,363	57,641
Nov-13	2,043,506	786,042	1,402,175	79,442	2,058,348	132,166	55,301
Dec-13	2,217,487	838,413	1,513,324	82,714	2,044,362	147,994	43,708
Jan-14	2,433,950	1,139,945	1,778,851	89,735	2,097,774	159,219	46,887
Feb-14	2,109,326	1,081,728	1,592,210	83,259	2,081,593	172,915	48,644
Mar-14	2,070,898	1,034,218	1,688,876	85,262	2,083,605	167,536	61,816
Apr-14	1,534,312	505,218	1,364,167	80,805	2,097,642	176,814	59,708
May-14	1,868,097	350,750	1,735,886	97,011	2,248,948	156,190	56,213
Jun-14	3,285,105	477,725	1,799,643	100,904	2,430,687	157,392	69,922
Jul-14	3,484,133	505,883	1,867,326	99,501	2,532,510	163,476	70,828
Aug-14	2,764,118	427,660	1,859,158	97,290	2,367,480	157,180	65,624
Sep-14	3,138,236	511,954	1,780,347	105,141	2,472,099	161,608	58,123
Oct-14	1,560,042	404,550	1,395,390	84,595	2,276,138	158,377	52,583
Nov-14	1,952,958	778,754	1,459,239	77,687	2,003,183	147,945	46,566
Dec-14	2,034,765	686,080	1,458,595	76,730	2,031,895	130,232	42,518
Jan-15	2,243,194	1,098,786	1,646,201	82,493	2,073,719	146,194	43,342
Feb-15	2,247,342	1,373,473	1,793,580	88,111	2,084,993	140,504	51,543
Mar-15	2,116,065	1,036,730	1,502,919	75,945	2,046,767	147,666	53,129
Apr-15	1,572,280	590,066	1,302,357	71,918	2,026,423	152,490	53,547
May-15	2,792,402	453,030	1,748,979	92,507	2,482,424	165,136	50,874
Jun-15	3,040,326	454,778	1,845,671	92,953	2,503,982	147,782	58,671
Jul-15	3,502,888	537,249	1,860,041	90,510	2,517,630	156,260	58,620
Aug-15	3,116,339	482,196	1,828,152	88,545	2,500,979	144,061	57,501
Sep-15	3,152,945	481,309	1,902,452	98,060	2,585,001	146,595	48,982
Oct-15	1,605,056	533,597	1,373,339	70,421	2,081,316	151,094	45,461
Nov-15	1,761,445	594,107	1,291,908	67,261	2,064,008	143,971	46,050
Dec-15	1,961,156	574,013	1,276,851	65,367	1,951,554	159,103	37,700
Jan-16	2,199,594	1,013,870	1,561,829	71,925	2,103,579	162,480	39,919
Feb-16	2,110,009	1,147,132	1,507,644	69,371	2,056,348	153,387	42,092
Mar-16	1,715,264	685,846	1,379,359	66,380	2,033,592	149,647	53,270
Apr-16	1,559,479	640,484	1,377,108	67,324	2,111,144	139,976	51,726
May-16	2,689,585	415,661	1,658,394	80,615	2,278,588	146,993	51,774
Jun-16	2,872,098	437,120	1,726,995	82,713	2,393,248	147,672	60,650
Jul-16	3,397,901	497,519	1,913,656	86,249	2,565,752	148,169	56,806
Aug-16	3,872,977	559,229	1,926,793	87,708	2,555,966	155,771	59,824
Sep-16	3,414,206	492,344	1,915,050	89,759	2,526,525	155,730	45,499
Oct-16	1,797,857	472,948	1,560,289	72,654	2,171,133	149,319	48,526
Nov-16	1,788,239	594,885	1,283,418	62,495	1,998,510	138,193	42,947
Dec-16	2,170,027	970,674	1,558,157	67,728	2,097,700	150,938	37,529
Jan-17	2,210,845	1,069,010	1,589,273	69,214	2,094,408	163,341	40,325
Feb-17	1,932,636	810,687	1,440,600	64,215	1,998,195	157,595	43,605
Mar-17	1,939,632	869,169	1,476,942	65,374	2,086,250	159,079	51,583
Apr-17	1,716,758	465,013	1,421,723	67,027	2,230,328	141,918	52,911
May-17	2,693,888	424,035	1,761,172	82,146	2,397,770	141,238	52,181
Jun-17	3,441,622	510,537	1,836,286	81,527	2,460,552	155,452	58,330
Jul-17	3,547,555	512,386	1,889,922	83,086	2,569,692	137,723	55,335
Aug-17	3,189,730	471,133	1,830,708	81,403	2,520,703	136,809	57,948
Sep-17	2,870,752	441,473	1,780,426	82,180	2,491,999	143,288	45,209
Oct-17	2,206,010	367,641	1,592,772	74,030	2,366,387	135,647	43,516
Nov-17	1,752,701	666,093	1,300,424	60,072	2,134,720	113,087	40,011
Dec-17	2,379,311	1,076,429	1,468,585	63,749	2,111,395	124,881	34,110
Jan-18	2,396,006	1,269,481	1,575,186	66,343	2,164,864	130,209	37,535
Feb-18	1,932,722	917,612	1,454,504	62,492	2,074,899	126,629	37,815
Mar-18	1,875,873	690,894	1,386,912	61,210	2,007,720	124,791	46,768
Apr-18	1,616,927	597,222	1,295,472	59,212	1,979,999	122,360	47,879
May-18	2,489,398	390,705	1,592,906	71,154	2,371,481	129,998	50,478
Jun-18	3,294,874	495,200	1,793,687	77,761	2,459,274	120,192	52,680
Jul-18	3,820,494	556,906	1,903,671	82,042	2,556,788	115,153	52,870
Aug-18	3,651,901	528,342	1,944,201	84,890	2,636,777	119,250	54,236
Sep-18	3,583,074	516,725	1,963,624	86,306	2,667,923	118,735	42,351
Oct-18	2,136,326	453,954	1,588,979	70,695	2,425,035	129,844	40,695
Nov-18	1,929,527	843,605	1,363,552	57,693	2,009,038	137,692	39,413
Dec-18	2,066,786	813,890	1,387,511	59,746	2,061,706	131,058	34,147
Jan-19	2,310,233	1,293,982	1,624,523	63,676	2,087,731	144,024	36,610
Feb-19	2,083,119	1,185,811	1,637,432	64,783	2,072,466	141,428	38,021

	Peak (KW) by Rate Class - NCP (From Attachment SDR-COS-1(b))						
Date	**R**	**RH**	**GS**	**PD**	**HT**	**EP**	**Lighting**
Mar-19	1,933,240	912,707	1,467,769	59,837	2,051,574	129,009	48,621
Apr-19	1,521,293	600,641	1,279,340	55,549	2,063,512	133,681	48,582
May-19	2,262,449	382,719	1,668,426	70,070	2,325,156	122,235	49,051
Jun-19	3,052,500	452,737	1,728,832	67,104	2,359,360	131,704	50,917
Jul-19	4,100,660	597,358	1,892,428	75,173	2,475,051	111,407	29,968
Aug-19	3,337,554	490,590	1,831,501	73,356	2,385,657	112,317	54,180
Sep-19	2,853,395	435,123	1,748,097	72,772	2,367,167	116,634	40,966
Oct-19	2,645,793	413,197	1,749,730	71,520	2,304,905	110,331	42,493
Nov-19	1,787,354	723,383	1,340,570	54,496	1,881,599	103,445	42,116
Dec-19	2,049,174	908,189	1,480,519	57,837	1,954,622	104,828	33,936
Jan-20	1,964,854	889,522	1,437,221	56,976	2,004,261	98,910	34,561
Feb-20	1,791,483	916,127	1,374,028	54,569	1,938,096	94,964	39,720
Mar-20	1,731,531	654,743	1,249,100	51,751	1,833,800	98,141	47,205
Apr-20	1,558,851	505,764	904,720	39,099	1,563,563	42,644	46,578
May-20	2,321,091	433,137	1,176,939	50,679	1,896,434	50,355	43,867
Jun-20	3,329,610	503,663	1,509,696	61,485	2,118,390	60,527	51,972
Jul-20	3,955,972	579,399	1,714,087	67,263	2,234,183	111,591	51,236
Aug-20	3,734,690	549,762	1,651,317	65,022	2,245,853	109,477	51,971
Sep-20	2,739,766	414,028	1,539,761	60,793	2,103,005	102,039	39,064
Oct-20	1,551,855	498,864	1,160,251	47,517	1,847,558	106,686	41,561
Nov-20	1,819,448	683,255	1,177,545	47,242	1,786,792	88,214	42,953
Dec-20	2,340,716	869,809	1,269,995	47,399	1,795,247	91,525	33,948
Jan-21	2,221,842	883,219	1,382,674	49,725	1,857,742	75,268	35,711
Feb-21	2,194,390	875,163	1,350,158	50,207	1,834,852	95,394	40,799
Mar-21	1,862,973	773,135	1,294,348	50,372	1,818,243	76,971	45,208
Apr-21	1,704,389	596,269	1,283,894	51,722	1,985,302	75,712	45,256
May-21	2,991,578	467,297	1,514,053	58,408	2,093,139	77,822	45,423
Jun-21	3,927,463	570,327	1,816,624	67,136	2,374,115	82,196	48,269
Jul-21	3,686,743	538,640	1,748,321	65,896	2,342,208	91,897	49,955
Aug-21	3,732,644	542,546	1,785,641	69,371	2,411,790	93,927	50,270
Sep-21	2,903,910	432,804	1,658,547	66,791	2,317,963	111,930	39,532
Oct-21	2,020,613	344,115	1,358,586	55,723	2,072,664	122,164	39,472
Nov-21	1,851,137	641,519	1,232,002	47,350	1,803,474	103,380	38,750
Dec-21	2,007,123	750,518	1,285,688	48,981	1,838,593	97,214	32,208
Jan-22	2,247,870	1,088,548	1,458,596	52,082	1,925,767	124,010	34,196
Feb-22	2,005,569	1,026,279	1,405,918	85,872	1,927,677	91,668	41,319
Mar-22	1,856,516	780,573	1,311,838	50,176	1,829,034	98,563	45,308
Apr-22	1,580,771	475,493	1,253,351	45,670	1,852,800	91,530	44,382
May-22	3,346,050	507,233	1,642,855	60,570	2,237,451	95,829	44,864
Jun-22	3,079,020	465,121	1,591,423	57,098	2,134,397	100,362	48,360
Jul-22	3,902,968	567,613	1,805,569	65,104	2,349,539	113,912	48,515
Aug-22	3,814,764	547,020	1,845,093	66,531	2,392,024	125,447	49,570
Sep-22	2,921,277	432,095	1,518,070	58,502	2,143,162	119,300	38,616
Oct-22	1,522,598	435,936	1,145,508	46,188	1,824,190	115,239	39,028
Nov-22	1,940,300	734,421	1,239,813	48,415	1,831,672	116,525	37,105
Dec-22	2,379,247	1,180,290	1,316,759	48,335	1,834,070	115,517	32,595
Jan-23	1,840,319	667,321	1,298,973	47,752	1,838,922	108,419	34,011
Feb-23	2,006,045	1,005,330	1,327,427	48,456	1,840,936	119,063	40,934
Mar-23	1,785,908	672,895	1,284,076	47,502	1,864,883	114,168	43,996
Apr-23	1,715,176	503,841	1,299,970	49,129	1,888,053	103,306	43,772
May-23	1,759,227	359,562	1,324,785	48,880	1,938,985	102,328	44,654
Jun-23	2,539,458	402,273	1,524,050	55,338	2,147,946	99,975	47,370
Jul-23	3,601,870	522,434	1,731,588	61,666	2,302,128	96,138	48,733
Aug-23	3,011,827	454,733	1,633,330	59,357	2,291,625	97,378	48,981
Sep-23	3,578,440	527,084	1,818,882	67,759	2,416,494	101,302	38,682
Oct-23	1,868,326	378,172	1,414,854	54,031	2,060,933	91,767	38,863

Date	R	RH	GS	PD	HT	EP	Lighting	
	Peak (KW) by Rate Class - NCP (From Attachment SDR-COS-1(b))							
Summary of Observations								
	R	**RH**	**GS**	**PD**	**HT**	**EP**	**Lighting**	**Total**
Annual NCP and NCP Allocation								
10/13 - 9/14 NCP	3,484,133	1,139,945	1,867,326	105,141	2,532,510	176,814	70,828	9,376,699
10/13 - 9/14 NCP Allocation	37.2%	12.2%	19.9%	1.1%	27.0%	1.9%	0.8%	
10/14 - 9/15 NCP	3,502,888	1,373,473	1,902,452	98,060	2,585,001	165,136	58,671	9,685,680
10/14 - 9/15 NCP Allocation	36.2%	14.2%	19.6%	1.0%	26.7%	1.7%	0.6%	
10/15 - 9/16 NCP	3,872,977	1,147,132	1,926,793	89,759	2,565,752	162,480	60,650	9,825,542
10/15 - 9/16 NCP Allocation	39.4%	11.7%	19.6%	0.9%	26.1%	1.7%	0.6%	
10/16 - 9/17 NCP	3,547,555	1,069,010	1,889,922	83,086	2,569,692	163,341	58,330	9,380,936
10/16 - 9/17 NCP Allocation	37.8%	11.4%	20.1%	0.9%	27.4%	1.7%	0.6%	
10/17 - 9/18 NCP	3,820,494	1,269,481	1,963,624	86,306	2,667,923	135,647	54,236	9,997,712
10/17 - 9/18 NCP Allocation	38.2%	12.7%	19.6%	0.9%	26.7%	1.4%	0.5%	
10/18 - 9/19 NCP	4,100,660	1,293,982	1,892,428	75,173	2,475,051	144,024	54,180	10,035,497
10/18 - 9/19 NCP Allocation	40.9%	12.9%	18.9%	0.7%	24.7%	1.4%	0.5%	
10/19 - 9/20 NCP	3,955,972	916,127	1,749,730	71,520	2,304,905	111,591	51,972	9,161,816
10/19 - 9/20 NCP Allocation	43.2%	10.0%	19.1%	0.8%	25.2%	1.2%	0.6%	
10/20 - 9/21 NCP	3,927,463	883,219	1,816,624	69,371	2,411,790	111,930	50,270	9,270,667
10/20 - 9/21 NCP Allocation	42.4%	9.5%	19.6%	0.7%	26.0%	1.2%	0.5%	
10/21 - 9/22 NCP	3,902,968	1,088,548	1,845,093	85,872	2,392,024	125,447	49,570	9,489,522
10/21 - 9/22 NCP Allocation	41.1%	11.5%	19.4%	0.9%	25.2%	1.3%	0.5%	
10/22 - 9/23 NCP	3,601,870	1,180,290	1,818,882	67,759	2,416,494	119,063	48,981	9,253,340
10/22 - 9/23 NCP Allocation	38.9%	12.8%	19.7%	0.7%	26.1%	1.3%	0.5%	
Minimum, Maximum and Average Annual NCP								
Minimum	36.2%	9.5%	18.9%	0.7%	24.7%	1.2%	0.5%	
Maximum	43.2%	14.2%	20.1%	1.1%	27.4%	1.9%	0.8%	
Average	39.5%	11.9%	19.6%	0.9%	26.1%	1.5%	0.6%	
NCP Contributions by Class in Last 3 Rate Cases								
2024	38.9%	12.8%	19.7%	0.7%	26.1%	1.3%	0.5%	
2021	43.2%	10.0%	19.1%	0.8%	25.2%	1.2%	0.6%	
2018	37.8%	11.4%	20.1%	0.9%	27.4%	1.7%	0.6%	
Absolute Value of Rate Case Deviation from Average								
2024	0.6%	0.9%	0.1%	0.1%	0.0%	0.2%	0.1%	
2021	3.7%	1.9%	0.5%	0.1%	0.9%	0.3%	0.0%	
2018	1.7%	0.5%	0.6%	0.0%	1.3%	0.3%	0.0%	

PECO ENERGY COMPANY
STATEMENT NO. 6-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

SURREBUTTAL TESTIMONY

WITNESS: TAMARA J. JAMISON

SUBJECT: CLASS COST OF SERVICE STUDY

DATED: AUGUST 2, 2024

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II. THE COMPANY'S CLASS COST-OF-SERVICE STUDY 1

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SURREBUTTAL TESTIMONY
OF
TAMARA J. JAMISON

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Tamara J. Jamison. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Manager, Revenue Policy. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, PA 19103.

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

A. Yes. I submitted direct and rebuttal testimony on behalf of the Company, which are designated as PECO Statement Nos. 6 and 6-R, respectively .

1. Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the analysis of PECO's historic load and revenue data presented in the rebuttal testimony of Philadelphia Area Industrial Energy Users Group ("PAIEUG") witness Billie S. LaConte to support PAIEUG's alternative revenue allocation that is not based on the results of the Company's class cost-of-service study ("COSS").

II. THE COMPANY'S CLASS COST-OF-SERVICE STUDY

3. Q. Does PAIEUG witness LaConte offer additional justification in her rebuttal testimony for her conclusion that PECO's COSS results may not be representative of the cost to serve each customer class?

A. Yes. Ms. LaConte reviews PECO's discovery responses identifying the drivers for changes in revenue for each customer class in the COSS in this rate case

("2024 COSS") compared to the COSS presented in PECO's last electric base rate case at Docket No. R-2021-3024601 ("2021 COSS") and providing the actual energy usage for each customer class over the last five years. *See* Exhibit BSL-1R (PECO Response to Interrogatory PAIEUG-III-1); Exhibit BSL-2R (PECO Response to Interrogatory PAIEUG-IV-2(b)); Exhibit BSL-3R (PECO Response to Interrogatory PAIEUG-IV-3(a)). According to Ms. LaConte, the data provided in those discovery responses show that 2021 COSS Residential class revenue increased by $37 million in the 2024 COSS due to higher usage but that actual Residential class usage declined in 2023 from 2022. She claims PECO's 2024 COSS should not provide the basis for revenue allocation in this proceeding because of the purported discrepancy between PECO's responses to PAIEUG Interrogatory Nos. III-1 and IV-2 and the Company's response to PAIEUG Interrogatory No. IV-3.

4. Q. Do you agree with Ms. LaConte's conclusion?

A. No. The revenue comparison showing a $37 million increase due to customer usage discussed by Ms. LaConte is between the forecasted revenue for the fully projected future test year ("FPFTY") of 2022 that was included in the 2021 COSS and the forecasted revenue for the FPFTY of 2025 that was included in the 2024 COSS prior to any rate increase.

PECO's actual non-weather-normalized load and revenue for 2023 (from the response to PAIEUG Interrogatory No. IV-3) is not part of the calculation in the response to PAIEUG Interrogatory Nos. III-I and IV-2 as Ms. LaConte states on pages 8 and 9 of her testimony, and thus, all comparisons Ms. LaConte makes

between 2021 and 2023 are irrelevant.

The $82.5 million revenue increase authorized by the Commission in PECO's last electric base rate case ("2021 Rate Case") for the Residential class was based on the customer and weather-normalized load profile across classes for the then-FPFTY of 2022. That revenue increase was translated into a rate that would recover $82.5 million using the forecasted 2022 customer and weather-normalized load profile. PECO properly implemented the rates approved in the 2021 Rate Case that went into effect on January 1, 2022. It is not expected that the revenue increase of $82.5 million approved in the 2021 Rate Case would remain static in subsequent base rate cases due to changes in the number of customers and weather-normalized load. The revenue included in the 2024 COSS is based on the number of customers and weather-normalized load profile across classes in the FPFTY of 2025.

III. CONCLUSION

5. Q. Does this complete your surrebuttal testimony at this time?

A. Yes. It does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. 2024-3046931**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

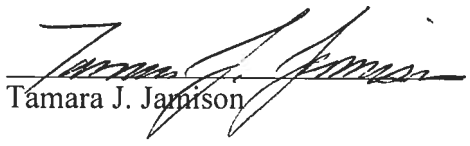
I, Tamara J. Jamison, hereby state that I am a Senior Manager, Revenue Policy for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 6
- PECO Exhibit TJJ-1
- PECO Exhibit TJJ-2
- PECO Exhibit TJJ-3
- PECO Exhibit TJJ-4
- PECO Exhibit TJJ-5
- PECO Exhibit TJJ-6
- PECO Exhibit TJJ-7
- PECO Exhibit TJJ-8
- PECO Exhibit TJJ-9

- PECO Statement No. 6-R
- PECO Exhibit TJJ-10
- PECO Exhibit TJJ-11
- PECO Exhibit TJJ-12

- PECO Statement No. 6-SR

Dated: August 5, 2024



Tamara J. Jamison

PECO Statement No. 7:

Direct Testimony of Joseph A. Bisti

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-2024-3046931

DIRECT TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECT: REVENUE ALLOCATION; RATE DESIGN; AND DEVELOPMENT OF PROPOSED NEW RATES

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

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

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as a Manager of Rate Analysts. I am responsible for retail tariff administration, project management, and regulatory affairs relating to PECO's gas and electric operations.

3. Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Economics from The College of New Jersey in 2000, a Master of Science in Training and Organizational Development from Saint Joseph's University in 2009, and a Graduate Certificate in Utility Management from Willamette University in 2012. In 2015, I earned a certification as a Project Management Institute Professional in Business Analysis. In September of 2022, I was promoted to my current position. My professional experience includes various roles involving business analysis, project leadership, and regulatory compliance within PECO's Retail Rates, Energy Acquisition, and Information Technology departments.

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

A. The purpose of my testimony is to describe: (1) how PECO proposes to allocate its claimed revenue increase among rate classes and explain the principles that guided PECO in developing its proposed revenue allocation; and (2) the changes PECO is proposing in the rate design for certain rate classes, why PECO is proposing these changes, and how the proposed new rates were developed.

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

A. I am sponsoring the following exhibits:

Exhibit JAB-1	Proposed Revenue Allocation, Proposed Increases by Class and Class Rates of Return and Relative Rates of Return under Proposed Rates
Exhibit JAB-2	Relevant Electric Service Tariff Pages (Blacklined to Show Changes)
Exhibit JAB-3	Comparison of Residential Customer Charges for Pennsylvania Electric Distribution Utilities
Exhibit JAB-4	Proof of Revenues at Present and Proposed Rates
Exhibit JAB-5	Modified Base Rate Recovery of CAP Revenues in USFC

II. REVENUE ALLOCATION

6. Q. Please state the principles that guided PECO in developing its proposed revenue allocation.

A. The proposed revenue allocation reflects a reasonable balance of accepted principles for designing utility rates. Specifically, PECO considered the following principles in developing its proposed revenue allocation:

1. The results of the class cost-of-service study ("COSS") prepared by Company witness Tamara J. Jamison and discussed in PECO Statement No. 6 should be used as a guide in allocating the proposed revenue increase among rate classes;

2. The overall proposed revenue allocation should produce reasonable movement toward the cost of service indicated by the COSS; and

3. Customer impacts should be considered, and PECO should attempt to avoid increases in revenue for major rate classes that, on a percentage basis, exceed two times the proposed system average increase.

7. Q. Has an exhibit been prepared showing the cost of service by rate class?

A. Yes, a summary of class cost-of-service data is provided in PECO Exhibit TJJ-1, sponsored by Ms. Jamison, and accompanies her direct testimony (PECO Statement No. 6). PECO Exhibit TJJ-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, 2025, which is the Fully Projected Future Test Year ("FPFTY") in this case. PECO Exhibit TJJ-1 also shows, at page 3, line 120, the increase or decrease in dollars that each rate class would have to receive for its revenues to equal its indicated class cost of service. As indicated by the guiding principles I summarized above, while the results of the Company's COSS are an important guide in evaluating its proposed revenue allocation, they are not the only factor that must be considered.

8. Q. Please discuss the principle of gradualism and how it influenced PECO's proposed revenue allocation.

A. The ratemaking principle of gradualism, as traditionally applied in Pennsylvania, guides utilities to avoid abruptly increasing rates in favor of slower adjustments that incrementally move rates toward the actual cost of service over time. PECO's proposed revenue allocation in this case attempts to balance gradualism

and other ratemaking principles, while limiting the degree to which rates for other classes diverge from their indicated cost of service. Under PECO's proposed revenue allocation and rate structure, the maximum increase for any rate class is 2.0 times the system average increase to prevent rate shock.

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

A. PECO's proposed revenue allocation is presented in PECO Exhibit JAB-1.

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

A. The proposed revenue allocation in PECO Exhibit JAB-1 is reasonable because it appropriately reflects the principles I discussed previously. Using the COSS discussed by Ms. Jamison as a guide, the Company developed the proposed rates to make meaningful movement toward each class's cost of service, as evidenced by the relative rates of return. The class rates of return and relative rates of return[1] at present and proposed rates in PECO Exhibit JAB-1 are provided in Table 1 below.

Table 1, Relative Rates of Return Under Company's Proposal

Rate Class	Under Present Rates	Under Proposed Rates
R	1.16	1.07
RH	0.59	0.82
GS	0.92	0.96
PD	0.76	0.90
HT	0.89	0.98
EP	0.57	0.73
Lighting	1.33	0.98

[1] A relative rate of return is the ratio of the rate of return for a rate class to the system average rate of return.

11. Q. Please explain the significance of the relative rates of return shown in PECO Exhibit JAB-1 to which you previously referred.

A. The relative rate of return is the ratio of the rate of return for a rate class to the system average rate of return. Relative rates of return are commonly used to test whether a proposed revenue allocation moves each rate class closer to, or at least no further from, the system average rate of return. A relative rate of return of 1.00 would mean the class rate of return equals the system average rate of return and, therefore, class revenues equal the class cost of service. Conversely, relative rates of return that depart from 1.00 indicate that the class rates of return are higher or lower than the system average rate of return and, therefore, the classes are providing revenues higher or lower than their indicated cost of service.

III. RATE DESIGN

12. Q. Explain in general how PECO proposes to change the charges within each rate schedule to recover the revenue allocated to each rate class.

A. PECO proposes to increase or decrease each of the charges within each rate schedule in proportion to the revenue increase or decrease allocated to that rate class, subject to certain rate design changes, discussed below. PECO Exhibit JAB-2 is a copy of the Company's Tariff Electric-Pa. P.U.C. No. 8 ("Tariff No. 8") that shows, by strike-out and blacklining, the proposed rate changes I discuss below, as well as the proposed changes in rules, regulations, rate schedules, and riders discussed by Megan A. McDevitt in PECO Statement No. 8. Tariff No. 8 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. 7 ("Tariff No. 7") and associated supplements. It is anticipated that Tariff No. 8, which was filed as part of this case on 60 days' notice, will be suspended by operation of Section 1308(d) of the Public Utility Code pending an investigation by the Commission. Because it is possible and, in fact, likely, that changes will be made, via subsequently filed supplements, to Tariff No. 7 during the period Tariff No. 8 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. 8 will be merged into the tariff that will be filed as part of PECO's compliance filing at the conclusion of this proceeding.

13. Q. Why is PECO proposing to increase customer charges for the residential class by a greater percentage than the proposed overall revenue increase for the class?

A. PECO is proposing to increase the customer charges in this manner to reduce the disparity between its current customer charge and the customer-related costs that should properly be recovered by that charge as reflected by Ms. Jamison in PECO Exhibit TJJ-4. The change is intended to align this charge more closely with the Company's customer-classified costs. As noted in PECO Exhibit JAB-3, the Company's current customer charge is lower than those of most other major electric distribution utilities in Pennsylvania.

A summary of the proposed customer charge increases for 2025 is shown in Table 2 below. These changes are intended to align customer charges more closely with the Company's customer-classified costs. In most cases, the proposed modified customer charges will be closer to, but still less than, the customer charges warranted by the customer-related costs identified by Ms. Jamison in PECO Exhibit TJJ-4, at page 4, line 37.

Table 2, Proposed Customer Charge Increases

Rate Class	Present Customer Charge	Customer-Related COSS $/Month/Customer (PECO Exhibit TJJ-4)	Proposed Customer Charge	Proposed % Increase
R and RH	$10.50	$33.28 and $33.58	$14.28	36%
GS – Single Phase – No Demand	$18.99	$39.71	$24.47	29%
GS – Single Phase – With Demand	$24.21		$31.20	29%
GS - Polyphase	$57.94		$74.66	29%
PD	$295.94	$297.61	$297.61	0.5%
HT	$353.84	$371.67	$371.67	5%

PECO's Service Location charges for certain Lighting class rates are also intended to recover a portion of the Company's customer-classified costs. Since the results of PECO's COSS indicating an increase in customer-related costs for Lighting (PECO Exhibit TJJ-4 at page 3, line 16), PECO also proposes to increase Service Location charges for the applicable Lighting class rates as shown in Table 3 below.

Table 3, Proposed Service Location Charge Increases

Lighting Rate	Present Location Charge	Proposed Location Charge	Proposed % Increase
SL-E – Street Lighting Customer-Owned Facilities	$6.65	$7.65	15%

SL-C – Street Lighting Control Customer-Owned Facilities	$5.63	$6.48	15%
TLCL – Traffic Lighting Constant Load Service	$3.67	$4.22	15%
AL – Alley Lighting in City of Philadelphia	$2.33	$2.68	15%

14. Q. Why is it important to increase customer charges and service location charges so those charges are closer to customer-classified costs?

A. Customer-classified costs are, by definition, costs that vary based on the number of customers, not usage. Such costs include, principally, but not exclusively, the cost of meters, customer service lines, billing and meter reading. Consequently, customer-classified costs are, on average, the same amount for each customer within a rate class. Accordingly, customer-classified costs are appropriately recovered in the customer charge, which is the same for each customer served under a given rate schedule. A utility should, to the extent practicable, avoid including customer-classified costs in variable distribution charges because to do so would make the recovery of customer-related costs a function of customers' usage, which they are not.

Misplacing customer costs in variable distribution charges has adverse consequences. First, it can create inappropriate intra-class subsidies because some customers will pay more than their share of customer-classified costs and others less, based on their relative levels of usage each month. Second, because customer costs, which are a fixed amount per customer, would be recovered in a charge that applies to usage, which varies, the Company could recover either too

little or too much of its customer-related costs because of variations in customer usage.

In summary, putting customer costs in the wrong element of a rate can be unfair to both customers and the utility. For these reasons, among others, customer-related costs in a utility's cost of service should be charged to customers in a manner that appropriately reflects the nature of the costs incurred, subject to consideration of the principle of gradualism.

15. Q. What residential customer charge is PECO proposing?

PECO is proposing a residential base customer charge of $14.28 per month (excluding consumer education surcharges). This customer charge will be closer to, but still less than, the customer charge warranted by the customer-related costs identified by Ms. Jamison in PECO Exhibit TJJ-4. The revenue to be recovered from this customer charge was deducted from the total revenue target for the residential class to determine the revenue to be recovered in the variable distribution service charge. The variable distribution service charge was changed to recover the balance of the residential class revenue not recovered by the customer charge.

16. Q. Is PECO proposing changes to customer charges for other rate classes?

A. Yes, PECO is also proposing increases to customer charges as shown in Table 2 above and in PECO Exhibit JAB-4. As discussed above, customer charges are designed to recover the customer-related fixed costs of providing service and therefore should be established to align with actual customer-related costs of providing those services as evidenced by Ms. Jamison in PECO Exhibit TJJ-4.

IV. CUSTOMER ASSISTANCE PROGRAM ("CAP") COST RECOVERY

17. Q. Mr. Bisti, please provide an overview of PECO's existing Universal Service Fund Charge ("USFC").

A. The USFC is PECO's Commission-approved rate mechanism for recovery of the costs of PECO's universal service programs that are not included in base rates. The USFC is an automatically adjusted surcharge created pursuant to Section 1307(a) of the Pennsylvania Public Utility Code.

USFC costs are reconciled on an annual basis using actual costs for a historic twelve-month period ("E-Factor") and projected costs for the future twelve-month period ("C-Factor"). Interest accrues from the month in which over/under collection of USFC costs occurs to the midpoint of the collection period, the sum of which results in a credit or charge to customers if costs are over- or under-collected, respectively. The cumulative amount (either positive or negative) at the end of the reconciliation period determines the E-Factor to be included in calculation of the next USFC for the subsequent period. PECO normally files its USFC reconciliation and annual rate adjustment in October of each year, with the new USFC rate becoming effective on the following January 1.

18. Q. Please describe the CAP "shortfall."

A. As explained by Company witness Jacqueline F. Golden in PECO Statement No. 10, PECO's CAP uses a percentage-of-income-based approach to provide bill credits to qualifying low-income residential customers. A portion of the cost of the aggregate benefits provided through PECO's electric CAP rider is recovered through base rates paid by residential distribution service customers.

As explained by Ms. Golden, the CAP "shortfall" refers to the amount of aggregate bill credits (in dollars) provided to CAP customers each year that is not included in base rates. This shortfall is recovered from or refunded to PECO's residential customers on an ongoing basis through the USFC, with annual reconciliation of any over/under collections as described above. The USFC is currently adjusted so that residential customers pay 73% of the total CAP shortfall amount. The remaining 27% of the CAP shortfall is absorbed by PECO to account for the estimated impact to bad debt expense and working capital.

19. Q. Is PECO proposing to increase the amount of electric CAP bill credits included in its base rates in this proceeding?

A. Yes. As explained by Ms. Golden, PECO is proposing to increase the aggregate value of bill credits provided to electric CAP customers currently included in its base rates from $86 million to $145.2 million and to change the offset factor applied to reconcilable CAP costs reflected in the USFC formula from 27% to 10.5%. PECO Exhibit JAB-5 illustrates the impact of these changes on the C-Factor and E-Factor calculations for PECO's USFC.

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

20. Q. Have you prepared a summary of distribution revenues at present and proposed rates for each rate class?

A. Yes. PECO Exhibit JAB-1 shows revenue at both present rates and proposed rates, as well as the percentage increases each class will receive on an overall basis.

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

A. Yes. PECO Exhibit JAB-4 is a proof of revenue with respect to PECO's present and proposed rates, based on pro forma billing determinants for the FPFTY. This exhibit is tied to the portion of PECO Exhibit JAB-1 that addresses the increased revenue that would be required.

22. Q. Please explain the adjustment made to the proof of revenues at present rates for the Company's Distribution System Improvement Charge ("DSIC").

A. The DSIC is a rate adjustment mechanism that permits PECO to recover the fixed costs of DSIC-eligible property between base rate cases through a separate, reconcilable charge established pursuant to Section 1353 of the Public Utility Code. The Commission approved PECO's establishment of a DSIC by its final order entered October 22, 2015, at Docket No. P-2015-2471423. PECO began to charge a DSIC effective with bills rendered on or after April 1, 2018. The Company is currently charging a DSIC of 1.01%, which the Company will adjust

to 1.29% effective with bills rendered on or after April 1, 2024.[2]

As required by the terms of the DSIC, the DSIC charge will be reduced to zero on the effective date of new rates established through this proceeding. The fixed costs of DSIC-eligible property that PECO will continue to recover through the effective date of its new base rates have been included in the Company's claimed rate base and reflected in the revenue requirement used to establish its proposed rates. Consequently, to properly compare PECO's revenues at present rates to revenues at its proposed base rates, PECO's proof of revenue at present rates has been adjusted by customer class to include the revenues billed under its DSIC.

23. Q. How does PECO propose to scale-back the proposed rates if it is granted less than the revenue increase it requested?

A. In the event PECO is granted less than its requested increase, PECO proposes that:

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

(2) the customer charges for all rate classes remain as proposed, and all other rates and charges for all rate schedules be reduced proportionately to produce the revenue target for each rate class.

VI. CONCLUSION

24. 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

[2] PECO's second Long Term Infrastructure Improvement Plan, a precondition for continuing recovery of eligible property through the DSIC, was approved by the Commission in an Order issued November 19, 2020, in Docket No. P-2020-3020974.

proposed rate design changes are consistent with the results of the COSS identified by Ms. Jamison and applicable principles of rate structure and rate design, including gradualism. In addition, the proposed customer charge for the residential class is in line with those of other major Pennsylvania electric distribution utilities.

25. Q. Does this conclude your direct testimony?

A. Yes, it does.

PECO Exhibit JAB-1:

Proposed Revenue Allocation, Proposed Increases by Class and Class Rates of Return and Relative Rates of Return Under Proposed Rates

PECO Energy Company (Electric)
Proposed Revenue Allocation and Rates of Return by Rate Class

Rate Class	(1) Current Distribution Revenue	(2) Proposed Distribution Revenue	(3) *(2) - (1)* Distribution Revenue Ask	(4) 2024 GSA / TSC Working Capital Adjustment	(5) *(3) + (4)* Net of 2024 GSA/TSC Adjustment	(6) *(5) / (1)* % Increase	(7) Increase vs. System Avg
Re□ide□tia□R□	□ □□□1 □□□□□	□ 1□1 □□□□□□□□1	□ □□□□□□□□□	□ □□□□□□	□ □□□□□0 □□0	□□□□	0□□
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Ge□era□□er□i□e □G□□	□ □□□01 □□□□	□ □□□□□□□1	□ □□□□0 □□□	□ □□□□□□	□ □□□□□□□□	□□□□	1□1□
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E□e□tri□Pro□□□io□ □EP□	□ □0 □□□□	□ □□□□0□	□ □□□0 0□0	□ □□0 □1□	□ □□□□□□	□□□□	1□□
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Total	□ 1□□□1 □□□□	□ □0 □□□0 □□□	□ □□□□1 □□	□ □□0 □0 □□	□ □□□□1 □□	□□□□	

Rate Class	(8) Present Rate of Return	(9) *(8) / Average of (8)* Present Relative Rate of Return	(10) Proposed Rate of Return	(11) *(10) / Average of (10)* Proposed Relative Rate of Return
Re□ide□tia□R□	□1 □□	1□1□	□□□□	1□0□
Re□ide□tia□Heati□g □RH□	□□□□	0□□□	□□□□	0□□□
Ge□era□□er□i□e □G□□	□0 □□	0□□□	□□□□	0□□□
Pri□ar□Di□trib□tio□ □PD□	□□□□	0□□□	□1 □□	0□□0
High Te□□io□ □HT□	□□□□	0□□□	□□□□	0□□□
E□e□tri□Pro□□□io□ □EP□	□□□1□	0□□□	□□□1□	0□□□
□ighti□g	□□□□	1□□□	□□□□	0□□□
Total	□□□1□		□□□□	

PECO Exhibit JAB-2:

Relevant Electric Service Tariff Pages (Blackline)

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SUPERCEDES ELECTRIC PA P.U.C. NO. 7 AND ALL SUPPLEMENTS THERETO

PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 4.

Issued March 28, 2024 **Effective May 27, 2024**

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ISSUED BY: M. A. Innocenzo – President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE

LIST OF CHANGES MADE BY THIS SUPPLEMENT

LIST OF COMMUNITIES SERVED - Original Page No. 4 – Delaware and Montgomery Counties updated.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS – Original Page No. 7 - Holidays updated.

FEDERAL TAX ADJUSTMENT CREDIT (FTAC) – FTAC page deleted.

INCREMENTAL COVID-19-RELATED UNCOLLECTIBLE EXPENSE (ICUS) – Original Page No. 35

FIBER AFFILIATE REVENUE SURCHARGE (FARS) – Original Page No. 36

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC) - Original Page No. 44 - Revised the USFC formula to remove the "F" Correction Factor. Revise the "L" and "I" Factors and update the offset factor in the Reconcilable Customer Assistance Program Costs.

PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS Original Page No. 45 – Revise the CEC formula to remove the "S factor, remove obsolete language that refers to the coming transition to a competitive market and replace the term "procurement class" with "customer class" to ensure consistency with other sections of the electric tariff. Increase recovery amount of Consumer Education Costs.

PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT (TARC) – TARC page deleted.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE - Original Page No. 49 – reset the DSIC to 0%.

RATE R RESIDENCE SERVICE – Original Page No. 52 - Distribution prices updated. FTAC and TARC language removed. FARS and ICUS language added.

RATE R H RESIDENTIAL HEATING SERVICE – Original Page No. 53 - Distribution prices updated. FTAC and TARC language removed. FARS and ICUS language added.

RATE-GS GENERAL SERVICE- Original Page No. 57 – Distribution prices updated. Eliminated reference to single metering installation. Revise language in the Determination of Billing Demand paragraph. Correct misstatement in the Minimum Charge. FTAC and TARC language removed. FARS and ICUS language added.

RATE PD PRIMARY-DISTRIBUTION POWER - Original Page No. 59 - Distribution prices updated. FTAC and TARC language removed. FARS and ICUS language added.

RATE HT HIGH-TENSION POWER - Original Page No. 60 - Distribution prices updated. FTAC and TARC language removed. FARS and ICUS language added.

RATE EP – Original Page No. 61 - Distribution prices updated. FTAC and TARC language removed. FARS and ICUS language added.

RATE POL PRIVATE OUTDOOR LIGHTING – Original Page No. 62 – Distribution prices updated. FTAC and TARC language removed. FARS and ICUS language added.

RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES – Original Page No. 64 - Distribution prices updated. FTAC and TARC language removed. FARS and ICUS language added.

RATE SL-E STREET LIGHTING CUSOMTER OWNED FACILITIES Original Page No. 66- Distribution prices updated. FTAC and TARC language removed. FARS and ICUS language added.

RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITES - Original Page No. 68 - Distribution prices updated. FTAC and TARC language removed. FARS and ICUS language added.

RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE– Original Page No. 71 – Distribution prices updated. FTAC and TARC language removed. FARS and ICUS language added.

RATE AL – Original Page No. 73 - Distribution prices updated. FTAC and TARC language removed. FARS and ICUS language added.

APPLICABILITY INDEX OF RIDERS - Original Page No. 74 – page numbers updated.

ECONOMIC DEVELOPMENT RIDER - Original Page No. 83 - expand the availability of the EDR for both new and existing customers and the scope. Also, revise the Availability/Applicability section of the Economic Development Rider to remove the reference to provision IC.

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) - Original Page No. 85a, 86a – Updates reflecting the pilot extension through 2030 including changes to eligibility criteria, minimum demand requirements, and the calculation of the demand credit.

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) - Original Page No. 86 – Other Rider section updated.

NIGHT SERVICE GS RIDER - Original Page No. 89 - Distribution prices updated. FTAC language removed.

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LIST OF CHANGES MADE BY THIS SUPPLEMENT (continued)

NIGHT SERVICE HT RIDER - Original Page No. 90 - Distribution prices updated. FTAC language removed.

NIGHT SERVICE PD RIDER - Original Page No. 91 - Distribution prices updated. FTAC language removed.

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Modified from short period billing on supplier switch to reflection of multiple supplier switches within a single monthly bill.¶
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RULES AND REGULATIONS – 17.5 LATE FEES AND COLLECTIONS COSTS – Second Revised Page No. 27¶
Modified to indicate that the Company will not apply late fees to final bills.¶
¶
RULES AND REGULATIONS – 23.3 EGS SWITCHING – Second Revised Page No. 33¶
Replaced account number with Electric Choice ID number.¶
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APPLICABILITY INDEX OF RIDERS - Original Page No. 73 – Added a footnote to the Construction Rider which expands the applicability to Rate GS customers with demands greater than 500 kW.¶
¶
CUSTOMER ASSISTANCE PROGRAM ("CAP") – Original Page No. 79 - Removed the certification requirement pertaining to energy assistance grant for enrollment in the CAP Rider.¶
¶
ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) – Original Page No. 84 - Expand availability of the rider to include public transit.¶
¶
NIGHT SERVICE GS RIDER - Original Page No. 88- Distribution prices updated.¶ ... [1]

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LIST OF COMMUNITIES SERVED

PHILADELPHIA:
CITY AND COUNTY OF Philadelphia.

DELAWARE COUNTY:
CITY: Chester.

BOROUGHS: Aldan, Brookhaven, Chester Heights, Clifton Heights, Collingdale, Colwyn, Darby, East Lansdowne, Eddystone, Folcroft, Glenolden, Lansdowne, Marcus Hook, Media, Millbourne, Morton, Norwood, Parkside, Prospect Park, Ridley Park, Rose Valley, Rutledge, Sharon Hill, Swarthmore, Trainer, Upland, Yeadon.

FIRST-CLASS TOWNSHIPS: Aston, Darby, Haverford, Lower Chichester, Marple, Nether Providence, Radnor, Ridley, Springfield, Tinicum, Upper Chichester, Upper Darby.

SECOND-CLASS TOWNSHIPS: Bethel, Birmingham, Chester, Concord, Edgmont, Middletown, Newtown, Thornbury, Upper Providence.

BUCKS COUNTY:
BOROUGHS: Bristol, Chalfont, Doylestown, Dublin, Hulmeville, Ivyland, Langhorne, Langhorne Manor, Morrisville, New Britain, New Hope, Newtown, Penndel, Telford, Tullytown, Yardley.

FIRST-CLASS TOWNSHIPS: Bristol.

SECOND-CLASS TOWNSHIPS: Bedminster, Bensalem, Buckingham, Doylestown, Falls, Hilltown, Lower Makefield, Lower Southampton, Middletown, New Britain, Newtown, Northampton, Plumstead, Solebury, Upper Makefield, Upper Southampton, Warminster, Warrington, Warwick, Wrightstown.

MONTGOMERY COUNTY:
BOROUGHS: Ambler, Bridgeport, Bryn Athyn, Collegeville, Conshohocken, East Greenville, Green Lane, Hatboro, Jenkintown, Lansdale, Narberth, Norristown, North Wales, Pennsburg, Pottstown, Red Hill, Rockledge, Royersford, Schwenksville, Souderton, Telford, Trappe, West Conshohocken.

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

SECOND-CLASS TOWNSHIPS: East Norriton, Franconia, Horsham, Limerick, Lower Frederick, Lower Gwynedd, Lower Providence, Lower Salford, Marborough, Montgomery, Perkiomen, Salford, Skippack, Towamencin, Upper Frederick, Upper Merion, Upper Providence, Upper Salford, West Vincent, Whitemarsh, Whitpain, Worcester.

CHESTER COUNTY:
CITY: Coatesville.

BOROUGHS: Avondale, Downingtown, Kennett Square, Malvern, Modena, Oxford, Parkesburg, Phoenixville, South Coatesville, Spring City, West Chester, West Grove.

FIRST-CLASS TOWNSHIP: Caln.

SECOND-CLASS TOWNSHIPS: Birmingham, Charlestown, East Bradford, East Brandywine, East Caln, East Coventry, East Fallowfield, East Goshen, East Marlborough, East Nantmeal, East Nottingham, East Pikeland, East Vincent, East Whiteland, Easttown, Elk, Franklin, Highland, Kennett, London Britain, Londonderry, London Grove, Lower Oxford, New Garden, Newlin, New London, North Coventry, Penn, Pennsbury, Pocopson, Sadsbury, Schuylkill, South Coventry, Thornbury, Tredyffrin, Upper Oxford, Upper Uwchland, Uwchland, Valley, Wallace, Warwick, West Bradford, West Brandywine, West Caln, West Fallowfield, West Goshen, West Marlborough, West Nantmeal, West Nottingham, West Pikeland, West Sadsbury, Westtown, West Vincent, West Whiteland, Willistown.

YORK COUNTY:
BOROUGH: Delta.

SECOND CLASS TOWNSHIPS: Chanceford, Fawn, Lower Chanceford, Peach Bottom.

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HOW TO USE LOOSE-LEAF TARIFF

1. This Tariff is issued on the loose-leaf plan. Each page will be issued as "original page," consecutively numbered, commencing with the title page, which in all cases will be considered as Page No. 1. For example: "Original Page No. 2", "Original Page No. 3," etc.

2. All changes in, additions to, or eliminations from, original pages, will be made by the issue of consecutively numbered supplements to this Tariff and by reprinting the page or pages affected by such change, addition, or elimination. Such supplements will indicate the changes which they effect and will carry a statement of the make-up of the Tariff, as revised. The Table of Contents will be reissued with each supplement.

3. When a page is reprinted the first time, it will be designated under the P.U.C. number as "First Revised Page No...," the second time as "Second Revised Page No...," etc. First revised pages will supersede original pages; second revised pages will supersede first revised pages, etc.

4. When changes or additions to be made require more space than is available, one or more pages will be added to the Tariff, to which the same number will be given with letter affix. For example, if changes were to be made in Original Page No. 2 and, to show the changed matter, more than one page should be required, the new page would be issued as "First Revised Page No. 2, superseding Original Page No. 2"; and the added page would be issued as "Original Page No. 2A." If a second added page should be required, it would be Issued as "Original Page No. 2B." Subsequent reprints will be consecutively designated as "First Revised...," "Second Revised...," etc.

5. On receipt of a revised page it will be placed in the Tariff immediately following the page which it supersedes, and the page which is to be superseded thereby plainly marked "See following page for pending revision." On the date when such revised page becomes Effective the page superseded should be removed from the Tariff.

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DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS

a.c. - alternating current

Advanced Meter - Advanced Meter shall have the meaning set forth in the Electric Generation Supplier Coordination Tariff.

Advanced Meter Services - Advanced Meter Services shall have the meaning set forth in the Electric Generation Supplier Coordination Tariff.

Advanced Meter Service Provider or AMSP - The Company or an EGS that provides Advanced Meter Services.

AEPS – Alternative Energy Portfolio Standard – statute that requires electric distribution companies and electric generation suppliers to acquire a certain percentage of their energy from alternative energy sources.

Available rate - A rate which may be obtained by a customer if the use of service conforms to the character of service contemplated in the rate, and the location is such that this service can be supplied from existing facilities of the Company.

Bad credit - A customer shall be deemed by the Company to have bad credit if the customer has been delinquent on payment of two consecutive bills or three or more bills in the last twelve billing cycles or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles. Industrial and commercial customers also shall be deemed by the Company to have bad credit if the customer is insolvent, (as evidenced by a credit report prepared by a reputable credit bureau or credit reporting agency or public financial data, liabilities exceeding assets or generally failing to pay debts as they become due) or has a class of publicly-traded debt outstanding that is rated to be below investment grade, or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles.

Base Rate (or rate) - The Base Rates are Rates R, R-H, RS-2, GS, PD, HT, POL, SL-S, SL-E, SL-C, TLCL, EP, and AL.

Billing demand - The calculated or measured demand after correction, if any, for power factor; except that the billing demand may be limited to a minimum figure.

Btu - British thermal unit.

Capacity charge - A charge based upon demand, either with or without power factor correction.

Competition Act - The Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §2801, et seq.

Competitive Energy Supply - unbundled energy and capacity provided by an Electric Generation Supplier.

Consolidated EDC Billing - Billing provided by the Company as provided for in the Electric Generation Supplier Coordination Tariff.

Consolidated EGS Billing - Billing provided by an EGS as provided for in Electric Generation Supplier Coordination Tariff.

Continuous service – Service which the Company endeavors to keep available at all times.

Creditworthy - A creditworthy customer pays the Company's charges as and when due and otherwise complies with the Rules and Regulations of this Tariff or the PaPUC. To determine whether a customer is creditworthy with respect to a particular account, the Company will evaluate the customer's record of paying Company charges for all of the customer's other Company accounts, and may also take into consideration the customer's general credit.

Customer - Any person, partnership, association, or corporation, lawfully receiving service at a single meter location from the Company. For purposes of billing for an Electric Generation Supplier (as defined below), the term customer may include all meter locations for which a summary bill is provided. In addition, unless explicitly prohibited by the Public Utility Code or the Commission's Rules and Regulations, an EGS may act as agent for an end use customer upon written authorization to PECO Energy which may be part of the notice of EGS selection.

Customer's service extension - The facilities extending from the customer's service-receiving equipment to the Company's service supply lines.

Default Service (DS) - The provision of energy or energy and capacity by PECO Energy as Default Service Provider to customers that are: (1) not eligible to obtain Competitive Energy Supply, (2) choose not to obtain Competitive Energy Supply, (3) return to default service after having obtained Competitive Energy Supply or Competitive Default Service, or (4) who contract for Competitive Energy Supply from an EGS (as defined below) that fails to deliver such energy or energy and capacity.

Default Service Provider (DSP) – The incumbent EDC within a certificated service territory or a Commission approved alternative supplier of electric generation.

Demand - The maximum rate-of-use of energy during a specified time interval, expressed in kilowatts.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Direct Access - Direct Access shall have the meaning set forth in the Competition Act.

Electric Distribution Company (EDC) - Electric Distribution Company (EDC) shall have the meaning set forth in the Competition Act.

Electric Generation Supplier (EGS) - Electric Generation Supplier (EGS) shall have the meaning set forth in the Competition Act.

Electric Generation Supplier Coordination Tariff (or Supplier Tariff)- PECO Energy's Electric Generation Supplier Coordination Tariff, provides procedures for EGS & PECO EDC interaction to make arrangements necessary to implement Direct Access for retail customers.

Energy Supply Charge (Generation Charge) - PECO Energy's charge for energy or energy and capacity to customers that receive Default Service.

Energy charge - a charge based upon kilowatt-hours of use.

FERC - the Federal Energy Regulatory Commission.

Fixed Distribution Service Charge (Customer Charge) – A charge to recover costs caused by the presence of the customer on the system other than the costs associated with the customer's demand or energy consumption.

Holidays - New Year's Day, Martin Luther King, Jr.'s Birthday, Presidents' Day, Good Friday, Memorial Day, Juneteenth, Independence Day, Labor Day, Columbus Day, Veterans Day, Thanksgiving Day, Friday after Thanksgiving, Christmas Day and Sundays.

Hp, horsepower - As used herein, horsepower shall be computed as the equivalent of 750 watts.

Initial Contract Term - An initial contract term for a service location shall be 1) the customer's first Term of Contract for service to the location or 2) the first Term of Contract after the customer changes service for a location to a different Rate.

Interest Index – An annual interest rate determined by the average of one-year Treasury Bills for September, October and November of the previous year.

KV, kilovolts - 1000 volts.

KVA, kilovoltampere - Unit of measurement of rate-of-use, which determines electrical capacity, required; it is obtained by multiplying the voltage of a circuit by its amperage.

KW, kilowatt - Unit of measurement of useful power.

KWh, kilowatt-hour - Unit of measurement of energy; an amount equivalent to the use of one kilowatt for one hour.

Lumen - Unit of measurement of quantity of light.

Measured Demand - A customer's highest demand during a 30-minute time interval in a billing period.

Month - A month under this Tariff means 1/12 of a year, or the period of approximately 30 days between two regular consecutive readings of the Company's meter or meters installed on the customer's premises.

PaPUC or Commission - The Pennsylvania Public Utility Commission.

PECO Energy or the Company - PECO Energy Company.

Point of Delivery - The single service point at which the service-supply lines of the Company terminate and the customer's facilities for receiving the service begin.

PJM - PJM shall mean the PJM Interconnection, L.L.C.

PJM System - PJM System shall mean the transmission facilities located in the Mid-Atlantic Region that are controlled by PJM.

Power Factor - As used herein, power factor is, in a single-phase circuit, the ratio of the watts to the voltamperes, and in a polyphase circuit, is the ratio of the total watts to the vector sum of the volt-amperes in the several phases.

Principal Office – The Company's Main Office Building is located at 2301 Market Street, Philadelphia, Pa. 19103.

Property Line - The division line between land held in or for private use, and land in which the public or the Company has a right of use; or, the division line between separately owned or occupied land.

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DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Separate EDC Billing - Billing provided by the Company as provided for in the Electric Generation Supplier Coordination Tariff.

Separate EGS Billing - Billing provided by an EGS as provided for in the Electric Generation Supplier Coordination Tariff.

Service - The distribution of energy for use by the customer, including all things done by the Company in connection with such distribution. (The Company must approve the installation of parallel generation via an Interconnection Agreement before the customer operates that generation in parallel with the Company's distribution system.)

- standard single-phase secondary: alternating current, 60 hertz, in accordance with Tariff Rule 2.5 (Single-Phase Up To 150 kVA:

  (a) nominally 120/240 volts, 3 wires;
  (b) nominally 120 volts, 2 wires to installations consisting of not more than two 15-ampere branch circuits;
  (c) nominally 120/208 volts, 3 wires, for residential service, where available in conjunction with standard polyphase secondary 120/208 volts, 3-phase, 4 wires.

- standard polyphase secondary; alternating current, 60 hertz. Only one service is available to a building. However, the Company will provide standard service to customer premises containing multiple buildings in accordance with Tariff Rule 2.2 (Single-Point Delivery). For purposes of determining service capacity and parallel-generating capacity limits, a building is defined as a structure, separated from other structures, or a portion of a contiguous structure separated from the remainder of the structure by approved firewalls. When demand or service voltage requires the installation of transformation equipment on the owner's premises, the transformation shall consist of a pad mounted transformer installed at a location provided by the owner and approved by the Company outside the building or a transformer bank installed inside the building in a vault located on the ground floor or one story below grade, meeting National Electrical Code requirements. The Company will not install, own or maintain any conductors inside or beneath a building nor install indoor transformation in areas supplied by or designated to be supplied at 33,000 volts or greater.
  (a) nominally 120/240 volts, 2-phase, 5 wires; only available in areas supplied by 2-phase distribution facilities located along public highways or private rights-of-way and limited to service capacities of 100 kVA or less;
  (b) nominally 240 volts, 3-phase, 3 wires; a fourth wire neutral will be extended for the supply of 120/240 volt single-phase equipment in combination with the service where neither the service capacity required nor the parallel-generating capacity required exceeds 15 kVA on any one of the phases. Where the demand to a single premises exceeds 100 kVA, transformers will be installed on the premises at a suitable location provided by the owner. The service capacity and the parallel-generating capacity are both limited to 300 kVA for transformers located inside the building and 500 kVA for transformers located outside the building.
  (c) nominally 120/208 volts, 3-phase, 4 wires, (where 3-phase distribution is available) for the exclusive supply of secondary service to a building or group of contiguous buildings occupied by one or more than one customer, with transformers and secondaries installed on the premises at suitable locations provided by the owner. The service capacity and the parallel-generating capacity are both limited to 750 kVA for transformers located either inside or outside the building. When either exceeds 750 kVA for transformers located inside the building the only rate option available to the customer will be Rate HT. When either exceeds 750 kVA but remains at or below 1,500 kVA for transformers located outside of the building, the customer can request service at 277/480 volts, 3-phase 4-wires from transformers located outside of the building. Otherwise, the only rate option available to the customer will be Rate HT. When a suitable transformer location is not reasonably available on the premises and the demand does not exceed 100 kVA, service may be supplied at the Company's discretion from aerial distribution facilities located along public highways.
  (d) nominally 277/480 volts, 3-phase, 4 wires (where 3-phase distribution is available) for the exclusive supply of secondary service to a building occupied by one or more than one customer with transformers and secondaries installed on the premises at suitable locations provided by the owner. The service capacity and the parallel-generating capacity are both limited to 750 kVA for transformers located inside the building and 1,500 kVA for transformers located outside the building. If either exceeds these limits the only rate option available to the customer will be Rate HT.

- standard primary - unregulated alternating current, 60 hertz, nominally 2,400 volts, 2-phase, 3 wires, or nominally 4,160 volts, 3-phase, 3 or 4 wires. Availability of these voltages is limited to those locations served at these voltages as of July 6, 1987.

- standard high tension - unregulated alternating current, 60 hertz, nominally 13,200, 33,000, 69,000, 138,000, 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 non-bypassable and must be paid by any customer regardless of the voltage level at which the customer is served.

Service-supply lines - The facilities (conductors, cables, conduits, etc.) extending from the Company's facilities in the highway or other trunk line location to the facilities owned and maintained by the customer.

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DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Summary Billing Account - An aggregate bill prepared for two or more meter locations owned or legally controlled by the same partnership, association, corporation, or governmental agency etc. for: (1) the Company's charges for service; and/or (2) an EGS's charges for Competitive Energy Supply, as permitted by Rule 2.2.

Tariff - this Electric Service Tariff comprising the Base Rates, rules and regulations which in conjunction with Pennsylvania Public Utility Law and Pennsylvania Public Utility Commission Regulations govern the distribution of electric energy including all things done by the Company in connection with such distribution, and/or the supply of electric energy under Default Service, and other PaPUC jurisdictional services.

Variable Distribution Service Charge (Distribution Charge) - the variable supply charges for the provision of unbundled distribution service, including all things done by the Company in connection with such distribution service.

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RULES AND REGULATIONS

1. THE TARIFF

1.1 FILING AND POSTING. A copy of this Tariff, which comprises the Rates, Rules and Regulations under which service and Default Service will be provided to its customers by PECO Energy, is on file with the Commission and is posted and open to

inspection at the Principal Office of the Company. A copy of this tariff is also available on the Company's website at http://www.peco.com.

1.2 REVISIONS. This Tariff may be revised, amended, supplemented or otherwise changed from time to time in accordance with the Pennsylvania "Public Utility Law", and such changes, when effective, shall have the same force as the present Tariff.

1.3 APPLICATION. The Tariff provisions apply to everyone lawfully receiving service from the Company, under the rates therein, and the recipient of service, whether service is based upon contract, agreement, accepted signed application, or otherwise, shall be subject to the terms of the Tariff. In addition, the rates therein shall apply to everyone receiving service unlawfully or otherwise, including unauthorized use as referred to in Rule 4.7 of this Tariff. A customer will receive service under the rates and riders of this tariff effective with their first scheduled billing cycle after the effective date of the tariff or as otherwise indicated in this tariff.

1.4 BASIS OF CHARGE. Time elapsed is a factor in the supply of service and the rates and minimum charges named in this Tariff, while predicated on periods of supply of not less than one year, are stated in values for direct application only to monthly periods of service supply and will be adjusted for application to service supplied during other time intervals.

1.5 RULES AND REGULATIONS. The Rules and Regulations, filed as part of this Tariff, are a part of every contract for service made by the Company and govern all classes of service where applicable, unless specifically modified by a rate or rider provisions. The obligations imposed on customers in the Rules and Regulations apply as well to everyone receiving service unlawfully and to unauthorized use of service.

1.6 USE OF RIDERS. The terms governing the supply of service under a particular Base Rate may be modified or amended only by the application of those standard riders, filed as part of this Tariff, which are specifically mentioned as applicable to that rate in the Applicability Index of Riders.

1.7 STATEMENT BY AGENTS. No representative has authority to modify a Tariff rule or provision, or to bind the Company by any promise or representation contrary thereto.

2. SERVICE LIMITATIONS

2.1 CHARACTER. This Tariff applies only to the distribution and/or supply of electric energy of the standard characteristics available in the locality in which the premises to be served are situated. The Company does not offer to distribute and/or supply electric energy of nonstandard characteristics.

2.2 SINGLE-POINT DELIVERY The Company will provide standard distribution and/or supply through a single delivery and metering point for the total requirements at each separate premises of any person, partnership, association, or corporation, lawfully receiving service, except where, in the Company's sole judgment, special conditions warrant the installation of additional facilities. Unless otherwise stated herein, the Base Rates in this Tariff for each class of service are based upon that standard. Separate distribution and/or supply for the same customer at other points of consumption shall be separately metered and billed, except that: (1) when the Company is providing Consolidated EDC Billing, the Company will provide summary billing of its charges for and/or an EGS' charges (if requested by the EGS) for Competitive Energy Supply; and (2) when the Company is providing Separate EDC Billing, the Company will provide summary billing of its charges.

2.3 SINGLE-POINT AVAILABILITY. Service delivered at a single point is available to one or more buildings or units devoted essentially to a single purpose, provided and so long as:

(a) Such buildings or units are:
(1) held, possessed, and either utilized or operated as a single establishment by a single responsible entity, and
(2) unified on the basis of family, business, industry, enterprise, or governmental agency or through conveniences and services, such as heat, elevator, janitor, care of halls, walks and lawns, etc., furnished by such entity, and
(3) situated on a single or on contiguous land parcels except where such buildings or units constitute interdependent parts of a single industrial enterprise. In determining "contiguity" hereunder of parcels abutting opposite sides of public or private ways, the boundaries of such parcels shall be considered as extending to the center of such ways.

(b) There is granted and maintained to the Company easement or other rights, adequate in the Company's reasonable judgment to supply service direct to any such buildings or units if, as and when a cessation of any one or more of the conditions stated in paragraph lettered "a" above should occur, or there should arise in any manner a Company duty of such direct supply.

RULES AND REGULATIONS (continued)

(c) The transforming, receiving and distribution facilities on the customer's side of the delivery point, are:
(1) furnished, installed and maintained at the expense of the customer, and
(2) owned or leased by the customer, and
(3) operated and controlled by or at the expense of the customer.
(d) The Company is under no legal obligation of direct supply to any portion of said building or units or their appurtenances.
(e) A guarantee by deposit or otherwise is given and maintained to the Company sufficient in its reasonable judgment to insure it against loss in primary, secondary and/or distribution investment in the event of change in the nature of holding and possession of such buildings or units, or in the occupancy thereof, or in the type of service delivered thereto.
(f) All utilization equipment on the customer's side of the Company delivery point is furnished, installed, operated and maintained by the operator of the building or units supplied or by the tenants of such operator whose use of electricity is dependent upon the single-point delivery and metering of service.
(g) Any use of public highways by such operator for the latter's distribution facilities does not conflict or interfere with the franchise rights of the company.

2.4 COMPLIANCE WITH AVAILABILITY. The use of the Company's service shall not be for any purpose other than that covered by the availability provisions of the applicable Base Rate and/or riders.

2.5 SINGLE-PHASE UP TO 150 KVA. Single-phase secondary service is available for customer equipment with demand of or parallel-generation facilities having an aggregate nameplate rating up to 150 kVA. Any customer demand or generation equipment in excess of this amount will be supplied polyphase service. (The Company must approve the installation of parallel generation via an Interconnection Agreement before the customer operates that generation in parallel with the Company's distribution system.)

2.6 POLYPHASE LOADS AGGREGATING LESS THAN 7-1/2 HP. Polyphase service is not available for installations aggregating less than 7-1/2 horsepower, unless the excess cost of supplying polyphase rather a single-phase service is borne by the customer.

2.7 MOTORS. Service is not available to motors which do not meet the Company's standard requirements.

2.8 COMPLIANCE WITH BUILDING ENERGY CONSERVATION ACT STANDARDS. Before receiving any electric service to or for new or renovated residential buildings or additions thereto, as defined by Pennsylvania Building Energy Conservation Act (BECA) as amended by Act 98 of 1985, applicants for service must provide the Company with the compliance certification copy of the Pennsylvania Department of Community Affairs (DCA) "Notice of Intent to Construct" form as processed by DCA. A compliance certification copy of "Notice of Intent to Construct" will not be required by the Company if the new or renovated residential building is located in a municipality which has elected to administer the BECA and requires that a notice of intent to construct be filed with the municipality before or at the time that application is made for a building permit and the notice has, in fact, been filed.

3. CUSTOMER INSTALLATION

3.1 INFORMATION FROM THE CUSTOMER. The Company should be advised by the customer or applicant for service, in writing, preferably on a form supplied by the Company, of premises to be equipped for service, giving exact location, and details of all current consuming devices to be installed.

The customer shall supply the Company any and all information in its possession regarding potential or actual contamination, waste or hazardous materials or other adverse environmental conditions on the customers' premises on or near where the Company facilities are to be located. The customer has a continuing obligation to provide the Company with such information relating to the premises as the customer receives it. The Company also has a continuing right to inspect the customers' premises for the purposes of performing an environmental assessment.

3.2 METER LOCATION. There shall be provided, free of expenses to the Company, at a location outdoors, unless otherwise designated by the Company or another AMSP, which the Company or another AMSP will designate in writing upon request, a suitable place for the meter or meters and any other supply, protective or control equipment of the Company or another AMSP which may be required in the provision of service. The customer shall provide access and space, in an amount deemed necessary by the Company, to install and maintain its meter(s) and equipment. This location shall be convenient, unimpeded and easily accessible to the Company's employees, 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.

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 and other additional requirements that PECO will provide upon request.

4.3 CONTRACT DATA. The application shall contain a statement of the premises to be served, the rate under which service is desired, and such conditions or riders as are applicable to the special circumstances of the case.

4.4 RIGHT TO REJECT. The Company may place limitations on the amount and character of service it will supply or may reject applications for service: not available under a standard rate; which might affect service to other customers; which is to be delivered at a location or at a standard voltage that involves excessive cost; for bad credit; for the applicant's failure to provide identifying documentation; when an applicant's self-identification cannot be verified; or for other good and sufficient reasons. Customers cannot be denied Default Service or new service for failure to pay an EGS's charges.

The Company has the right to restrict service to only those locations which will not expose the Company to liability for known or suspected contamination, waste or hazardous materials or other adverse environmental conditions.

4.5 ACCEPTANCE. Before the Company affirmatively accepts an application, the Company will consider the application to be "pending". When an application is accepted, it constitutes the contract between the customer and the Company, subject to the Rules and Regulations. A customer or other recipient of service also becomes contractually obliged to the Company when service is provided according to the application either with or without modification, or when the customer otherwise receives service.

4.6 SPECIAL CONTRACTS. Standard contracts shall be for terms as specified in the statement of the rate, but where large or special investment is necessary for the supply of service, or where service is to be used for an emergency or temporary replacement of another method of operation, contracts of longer term than specified in the rate, or with special guarantees of revenue, or both, may be required.

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RULES AND REGULATIONS (continued)

4.7 UNAUTHORIZED USE. Unauthorized connection to the Company's facilities, and/or the use of service obtained from the Company without authority, or by any false pretense, may be terminated by the Company. The use of service without notifying the Company or the AMSP and enabling them to read its meter will render the user liable for any amount due for service provided to the premises from the time of the last reading of the meter, immediately preceding the customer's occupancy, as shown by the Company's books.

4.8 WITHDRAWAL OF APPLICATION. In the event the customer (or potential customer) withdraws an application for either new or modified service, the customer will reimburse the Company for all reasonable costs incurred by the Company in anticipation of providing the new or modified service.

5. CREDIT

5.1 PAYMENT OBLIGATION. For customers for whom the Company provides Consolidated EDC Billing or Separate EDC Billing, the provision of service for any purpose, at any location, is contingent upon payment of all charges provided for in this Tariff (and, for the same class of service (residential or non-residential) under the Company's Gas Service Tariff, if the customer also receives gas service at the same premises) as applicable to the location and the character of service.

The Company may, at its discretion, determine liability for a past due balance by:

1) Use of Company records that contain information previously provided to the Company;
2) Information contained on a valid mortgage, lease, deed or renter's license;
3) Use of commercially available public records databases;
4) Government and property ownership records.

5.2 PRIOR DEBTS. Service will not be furnished to former customers until any indebtedness to the Company for previous service of the same or similar classification has been satisfied or a payment arrangement has been made on the debt. This rule does not apply to the disputed portion of disputed bills under investigation. The Company will apply this rule to the disputed portion of disputed bills, if, and only if: (1) the Company has made diligent and reasonable efforts to investigate and resolve the dispute; (2) the result of the investigation is that the Company determines that the customer's claims are unwarranted or invalid; (3) the Commission and/or the Bureau of Consumer Services has decided a formal or informal complaint in the Company's favor and no timely appeal is filed; and (4) the customer nevertheless continues to dispute the same matter in bad faith.

5.3 GUARANTEE OF PAYMENTS. The Company may charge a security deposit before it will render service to an applicant or before the Company will continue to render service to a customer for whom the Company provides Consolidated EDC Billing or Separate EDC Billing. The Company may charge deposits to applicants and customers if they have bad credit, lack creditworthiness or as otherwise permitted by Commission statutes, rules, regulations, and as required by Federal Bankruptcy Law. The applicant or customer may be required to provide a cash deposit, letter of credit, surety bond, or other guarantee, satisfactory to the Company. The Company will hold the deposit as security for the payment of final bills and in compliance with the Company's Rules and Regulations. In addition, the Company may require industrial and commercial customers for which it may provide Consolidated EDC Billing or Separate EDC Billing to post a deposit at any time if the Company determines that the customer is no longer creditworthy or has bad credit or as otherwise permitted by Commission statutes, rules, regulations and as required by Federal Bankruptcy Law. The Company retains the right to charge customers additional deposits based upon continued bad credit or lack of creditworthiness and increased usage.

5.4 AMOUNT OF DEPOSIT. For residential customers, the deposit will be equal to one-sixth of the applicant's or customer's estimated annual bill for Company charges, based on applicable rates. A deposit from a residential customer shall conform to the requirements of 66 Pa. C.S. 1404(c) and applicable Pennsylvania Public Utility Commission regulations. For industrial and commercial accounts, the amount of the deposit shall be the Company's projection of the sum of the Company charges in the customer's two highest monthly bills in the 12 months following the deposit. The provisions of 11 U.S.C. §366(b) of the Federal Bankruptcy Code, or any successor statute or provision, shall, if inconsistent, supersede the provisions of this rule.

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RULES AND REGULATIONS (continued)

5.5 RETURN OF DEPOSIT. Deposits secured from a residential customer shall either be applied with interest to the customer's account or returned to the customer with interest in accordance with 66 Pa. C.S.§1404(C) and applicable Pennsylvania Public Utility Commission regulations. In cases of discontinuance or termination of service, deposits will be returned with accrued interest upon payment of all service charges and guarantees or with deduction of unpaid accounts. Deposits secured from a residential customer, plus accrued interest, which may be held until a timely payment history is established, are refunded when a ratepayer is not currently delinquent and has made on time and in full payments for service provided by the Company for 12 consecutive months. Deposits secured from a non-residential customer, plus accrued interest, which may be held until a timely payment history is established, are refunded when a ratepayer is not currently delinquent and has made on time and in full payments for service provided by the Company for 24 consecutive months. Any residential or commercial customer having secured the return of the deposit may be required to make another deposit in accordance with Commission statutes, regulations or Federal Bankruptcy Law if the Customer demonstrates bad credit or lacks creditworthiness subsequent to the return of the initial deposit.

5.6 INTEREST ON DEPOSIT. The Company will allow simple interest on cash deposits calculated as follows:

(A) with respect to residential accounts, interest, will be computed at the simple annual rate determined by the Secretary of Revenue for interest on the underpayment of tax under Section 806 of the Act of April 19, 1929 (P.L. 343, No. 176), known as the Fiscal Code

(B) with respect to commercial and industrial accounts, at the lower of the Interest Index or six percent;

Deposits shall cease to bear interest upon discontinuance of service (or, if earlier, when the Company closes the account).

5.7 CREDIT INFORMATION.

CUSTOMERS: In addition to information required otherwise hereunder, customers for whom the Company provides Consolidated EDC Billing or Separate EDC Billing shall be required to provide to the Company with such credit information, as the Company requires. The Company may report to a national credit bureau on credit history associated with past due amounts.

APPLICANTS: The Company's credit and application procedures for applicants are as follows: (1) positive identification of applicant obtained from previous customer record or through one of the major credit reporting bureaus 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.

The Company's credit scoring methodology and standards are as follows: The Company uses a commercially recognized credit scoring methodology that is within the range of generally accepted industry practice. The applicant's or customer's utility payment history determines the credit score. The Company uses this customer-specific credit score to either request or waive a security deposit.

5.8 APPLICABILITY TO CUSTOMERS RESIDING AT PLACE OF BUSINESS. For purposes of all of the provisions of this Rule 5, when a customer resides at a place of business or commercial establishment, legitimately served pursuant to a commercial or industrial rate schedule, that is not a residential dwelling unit attached thereto, the customer is not thereby entitled to any of the protections in the Pennsylvania Public Utility Code or the Commission's regulations implementing the Pennsylvania Public Utility Code, or to any of the provisions of these rules or this Tariff, that apply exclusively to deposits for residential customers.

6. PRIVATE PROPERTY CONSTRUCTION

6.1 COMPANY'S SERVICE LINES. Where the Company has distribution facilities of adequate capacity on the highway or in other trunk line location adjacent to the premises to be served, it will provide, own and maintain standard service-supply lines as follows:

(a) UNDERGROUND:

Underground cable construction to a point of delivery approximately 18 inches inside the property line of the customer, except:

(1) For secondary service to new residences or new apartment buildings, underground cable construction will be extended to a meter location or connection box located at the building or buildings, as designated by the Company and in accordance with Rule 7.3.

(2) The Company will make necessary repairs to customer-owned extensions of primary and secondary underground service-supply lines for residential customers at no charge. If such customer-owned extension requires replacement, the Company will make the replacement and assume ownership of the service-supply line with the Company bearing the cost up to 200 feet in length and the customer bearing the cost for all additional length.

(b) AERIAL:

A single span of aerial open wire or cable construction to the first suitable support of the customer, nominally 100 feet inside the property line of the customer. This customer support shall establish the point of delivery for the customer. The customer's support shall be so located that the service span will be free of obstruction and adequately supported as required by the size and weight of the conductors.

6.2 SERVICE - SUPPLY ALTERATIONS. Changes related to a service-supply line or a meter owned by the Company, including the installation of protective devices or visual markers to denote safe operating distance from the Company's facilities, for the accommodation of the customer, shall be at the expense of the customer. If the alteration to the Company's facilities is temporary in nature and the materials used in that alteration can later by re-used by the Company, as for example the installation of protective "hard cover" to allow a customer, developer, or contractor to work safely in close proximity to the Company's facilities, then at the Company's discretion it may charge a refundable deposit in lieu of charging the customer for the cost of the re-usable materials.

6.3 CUSTOMER'S SERVICE EXTENSION. The customer shall provide, own, inspect and maintain the service extension from the Company's service-supply lines to the point of delivery and receiving equipment. PECO may install a Company-owned meter, transformer (which transformer may serve one or more customers), or other required equipment, of its choice, on customer-owned property or facilities; Such installation does not alter the responsibility of the customer to provide, own, inspect, and maintain the required customer service extension to which such Company-owned facilities may be attached.

6.4 METERS AND TRANSFORMERS. The Company will provide, own and maintain any meter or meters, and also the transformer or transformers (both potential and current type transformers), required in the supply of service of the current characteristics specified by the Base Rate or rider under which the service is provided, unless the customer receives Advanced Meter Services from an AMSP in that case such AMSP will install, provide, own, and/or maintain the Customer's meter or meters while the Company will continue to own the potential and current type transformers. The supply of transformers by the Company shall be limited to those required for a single standard transformation.

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RULES AND REGULATIONS (continued)

6.5 TRAILER PARKS. Where it is established by plans, development, use or other facts that the operation of a trailer park is predominantly to provide rental locations for non-transient trailers, with not less than two nor more than four such locations, the Company, upon written application of the trailer park operator and upon the receipt of an enabling agreement and of adequate rights-of-way, will construct, own and operate within the trailer park specified aerial electric energy, the trailer park operator being liable for payment of service to trailer park tenants not contracting in writing for service in their own names. The Company's obligation to install or extend such distribution facilities within the trailer park is limited to the investment warranted by the anticipated revenue. Alterations of such distribution facilities at the request of the park operator when not for the purpose of serving additional trailer rental locations will be at the cost of the trailer park operator. A trailer park operator desiring underground distribution facilities within a trailer park consisting of less than five locations must bear the excess cost incident thereto. Specifications and terms for such underground construction will be furnished by the Company on request. In new trailer parks consisting of five or more locations, underground distribution facilities will be extended in accordance with Rule 7.3.

RULES AND REGULATIONS (continued)

7. **EXTENSIONS**

7.1 TRUNK LINE CONSTRUCTION. The Company will construct, own and maintain overhead or underground distribution facilities, either secondary, primary, or high tension, located on the highway or on rights-of-way acquired by the Company and used or usable as part of the Company's general distribution system.

7.2 LINE EXTENSIONS FOR STANDARD SERVICE.

A. DEFINITIONS. For the purposes of this rule, when capitalized herein, the below terms shall have the following meanings:

(1) Line Extension -- A single-phase or polyphase addition to the public utility electric supply line for the purpose of supplying standard service (as described under Rule 2 above, but not including Line Extensions for nonstandard service as described in Rule 3.7 above) to and connected with the customer's point of delivery which addition is so located that it cannot be supplied by means of a service line from the existing electric supply line.

(2) Contractor Cost -- The amount paid by the Company to a contractor for work performed on a Line Extension.

(3) Customer -- End use customer of the Company, or a developer.

(4) Direct Labor Cost -- The pay and expenses of the Company employees directly attributable to work performed on Line Extensions, but not including construction overheads or payroll taxes, workmen's compensation expenses or similar indirect expenses.

(5) Direct Material Cost -- The purchase price of materials used for a Line Extension, but not including related storage expenses. In computing Direct Material Costs, proper allowance shall be made for unused materials, materials recovered from temporary structures, and discounts allowed and realized in the purchase of materials.

(6) Total Construction Cost -- For single-phase Line Extensions, the estimated total cost to the Company for the construction of the Line Extension, which cost shall include: Contractor Cost, Direct Labor Cost, and Direct Material Cost. For polyphase Line Extensions, the estimated total cost to the Company for the construction of the Line Extension, which cost shall include: Contractor Cost, Direct Labor Cost, Direct Material Cost and allocated overheads. For projects requiring significant design work, the Company will provide a preliminary cost estimate and charge customers a non-refundable deposit of 10% of the total estimated costs to fund the detailed design work. The detailed design work cost will not be included in the Total Construction Cost of the Line Extension used to determine contribution in aid of construction ("CIAC").

(7) Capacity Adjusted Cost -- For polyphase Line Extensions, the Total Construction Cost of a Line Extension multiplied by the percentage of that Line Extension's capacity installed to serve the Customer's capacity needs.

(8) Revenue Guarantee Contribution -- The estimated Variable Distribution Service Charges, as defined in the "Definitions of Terms and Explanation of Abbreviations" Section of this tariff, to be received by the Company from the Customer for a twelve (12) month period commencing with the first month after the Line Extension is completed.

B. SINGLE-PHASE LINE EXTENSIONS FOR STANDARD SERVICE. For a Customer whose use of the Line Extension is not speculative, the Company will construct a single-phase Line Extension as follows. The Company will construct a Line Extension up to 2,500 feet without a charge to the Customer. For Line Extensions over 2,500 feet, a Customer shall pay the Company a contribution in aid of construction ("CIAC") equal to the amount by which the Total Construction Cost of the Line Extension beyond 2,500 feet exceeds the Customer's Revenue Guarantee Contribution for the first three (3) year period after the Line Extension is completed. A Customer who is not a developer must pay the CIAC in full prior to the construction of the single-phase Line Extension.

C. POLYPHASE LINE EXTENSIONS FOR STANDARD SERVICE. For a Customer whose use of the Line Extension is not speculative, the Company will construct a polyphase Line Extension, as follows. A Customer must pay the Company a CIAC equal to the amount by which the Capacity Adjusted Cost of the Line Extension exceeds the Customer's Revenue Guarantee Contribution for the first five (5) year period after the Line Extension is completed. A Customer who is not a developer must pay the CIAC in full prior to the construction of the polyphase Line Extension.

D. DEVELOPERS. Prior to the construction of any Line Extension, a developer may, in lieu of paying the full CIAC, pay a minimum of 35 percent (35%) of the CIAC and, for the remaining amount, post a surety bond in a form reasonably acceptable to the Company. The unpaid portion of the CIAC is subject to interest at the then applicable prime rate and is payable no later than twelve (12) months from the date of the initial payment.

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RULES AND REGULATIONS (continued)

E. SPECULATIVE LINE EXTENSIONS. A Line Extension is speculative when, in the Company's reasonable opinion there is doubt: (1) as to the continued use, or the level of use, of the new Line Extension by the Customer; or (2) as to the Company's recovery of the Total Construction Cost for a polyphase Line Extension if a Capacity Adjusted Cost is applied.

Under the first scenario of a speculative Line Extension, the Company will construct the Line Extension for a Customer, as follows: pursuant to an individual contract between the Customer and the Company, in addition to any CIAC, the Customer may be required to provide the Company a customer advance in the form of an up-front payment, or, if mutually agreed to by the Customer and the Company, a 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.
2. Developer - The party responsible for construction and providing improvements in a development; that is, streets, sidewalks, and utility-ready lots.
3. Development - A planned project which is developed by a developer/applicant for electric service set out in a recorded plot plan of five or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, mobile homes, or apartment houses, all of which are intended for year-around occupancy, if electric service to such lots necessitates extending the Company's existing distribution lines.
4. Distribution Line - An electric supply line of untransformed voltage from which energy is delivered to one or more service lines.
5. Service Line - An electric supply line of transformed voltage from which service is delivered to the residence.
6. Subdivision - A tract of land divided by a subdivider into five or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, or apartment houses, all of which are intended for year-around occupancy, if electric service to such lots necessitates extending the Company's existing distribution lines.

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RULES AND REGULATIONS (continued)

B. INSTALLATION OF DISTRIBUTION AND SERVICE LINES. All distribution and service lines installed pursuant to an application for electric service within a development will be installed underground, and will be owned and maintained by the Company. Pad-mounted transformers may be installed at the option of the Company. Excavating and backfilling will be performed by the developer of the project or by such other agent as the developer may authorize. The developer or its agent may also for the purpose of reducing civil work costs, install conduit for the Company's use in installing electrical service, if the conduit and associated excavation work meets PECO's requirements. The Company will then assume ownership of such conduit. Installation of service-related facilities will be performed by the Company or by such other agent as the Company may also be installed underground, upon terms and conditions prescribed elsewhere in this tariff. The Company will not be liable for injury or damage occasioned by the willful or negligent excavation breakage, or other interference with its underground lines occasioned by anyone other than its own employees or agents.

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.

Customers with privately owned or operated underground utility facilities on their premises may have obligations as facility owners under the Underground Utility Line Protection Act, 73 P.S. Section 176 et. seq. These include becoming a member of Pennsylvania One Call, maintaining said facilities, and providing approximate locations of said facilities with temporary markings within the required time period in response to Pennsylvania One Call notifications. Customers should create and retain as-built drawings reflecting the locations of said facilities on the premises and revise these drawings as necessary to reflect any changes made following installation. If said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work, the Company has the right to require the associated customer to bear all incremental costs necessary to ensure safe digging by the Company, including but not limited to subsurface utility excavation and engineering, materials, supplies, transportation, labor, and overhead. If 1) said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work or 2) the Company is unable to notify a facility owner of its intent for excavation or similar work covered under the Act because the facility owner is not a member of the Pennsylvania One Call system, the Company shall not be liable to customers or any other third parties for any damages, including property damage, economic damages, costs, associated consequential damages or personal injuries.

10.3 PROTECTION BY CUSTOMER. The customer shall protect the equipment of the Company on the premises, and shall not permit any person, except a Company employee having standard badge of the Company or other Company identification, to break any seals upon, or do any work on, any meter or other apparatus of the Company located on the customer's premises.

10.4 TAMPERING. In the event of the Company's meters or other property being tampered or interfered with, the customer being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter, and for any repairs or replacements required, as well as for costs of inspections, investigations, and protective installations.

RULES AND REGULATIONS (continued)

10.5 RIGHT OF ACCESS. The Company's identified employees shall have access to the premises of the customer at all reasonable times for the purpose of reading meters, and for installing, testing, inspecting, repairing, removing or changing any or all equipment belonging to the Company. In the event of an emergency, the Company shall have the right to access customer owned facilities and equipment for the purpose of restoring electric service, for the purpose of rendering the electric facilities safe and reliable, or for the purpose of reducing the likelihood of damage to the Company's facilities and equipment.

10.6 OWNERSHIP AND REMOVAL. All equipment supplied by the Company shall remain its exclusive property, and the Company shall have the right to remove the same from the premises of the customer at any time after the termination of service from whatever cause.

10.7 POLE REMOVAL OR RELOCATION REQUESTED BY RESIDENTIAL PROPERTY OWNERS. The cost for removal or relocation of distribution line poles and their associated attachments made pursuant to the request of a residential property owner who is not entitled to receive condemnation damages to cover the cost of such work shall be borne by the property owner and shall be limited to contractor, direct labor, and direct material costs incurred less maintenance expenses avoided as a result of the pole removal or relocation. The calculation of such cost for removal or relocation shall be in accordance with the Public Utility Commission Regulations - Title 52, Section 57.27.

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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.

RULES AND REGULATIONS (continued)

The Company shall establish procedures for emergency energy conservation, including, if it deems necessary, schedules of service interruption and suspension priorities to be followed as prescribed by the foregoing paragraph.

The Company may revise such procedure from time to time, and shall revise them if so required by the Pennsylvania Public Utility Commission. A copy of such procedures or of the revision thereof currently in effect shall be kept available for public inspection at each office at which the Company maintains a copy of its Tariff for public inspection, and another such copy shall be kept on file with the Pennsylvania Public Utility Commission.

12.5 NOTICE OF TROUBLE. The customer must immediately notify the Company if service is interrupted or is otherwise unsatisfactory due to defects, trouble, or accident, affecting the supply of service.

12.6 RELOCATION OF DELIVERY POINT. In the event that the Company shall be required by any public authority to place underground any portion of its mains, wires, or service-supply lines, or relocate any poles or feeders, the customer, at the customer's own expense, shall change the location of his point of delivery to a point readily accessible to the new location.

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RULES AND REGULATIONS (continued)

13. CUSTOMER'S USE OF SERVICE

13.1 RESALE OF SERVICE. Pursuant to Section 1313 of the Public Utility Code, 66 Pa. C.S. § 1313, a customer may resell Energy and Capacity and/or service provided by PECO Energy under its default service plan if: (1) the Company provides such service under a single contract at one application of an available Base Rate and for the total requirements of the premises served, and (2) the location and use of the service conforms to the availability requirements of this Tariff for provision to the customer for the customer's own account.

All residential units connected after May 10, 1980, except those dwelling units under construction or under written contract for construction as of that date must be individually metered by either the Company, the AMSP or the landlord for their basic electric service supply. Centrally supplied master metered heating, cooling or water heating service may be provided if such supply will result in energy conservation. The bill rendered by the reseller to any consumer shall not exceed the amount which PECO Energy would bill its own residential customers for the same quantity of service under the applicable tariffed residential rate.

The requirements for individually metered dwelling units in new construction may be waived at the sole discretion of the Company. Such waiver will only be granted when the owner can demonstrate to the Company that there are valid reasons for such waiver and that there will not be a significant impact on the consumption of an individual customer.

In accordance with the Commission's Policy Statement at Docket No. M-2017-2604382, the electricity sales by a person, corporation or other entity, not a public utility, owning and operating an electric vehicle charging facility for the sole purpose of recharging an electric vehicle battery for compensation shall not be construed to be sales to residential consumers and therefore do not fall under the pricing requirements of 66 Pa.C.S. § 1313. Such sales are therefore not considered a resale of service as defined in this tariff rule, Rule 13.1.

Electric Vehicle charging stations shall be constructed in accordance with the Company's service installation policies contained in its Electric Service Requirements Manual ("Blue Book"), a copy of which may be found at www.peco.com. The customer, who may be either the owner or the host of a third-party owned charging station, shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company.

13.2 FLUCTUATIONS. Electric service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system, and, in the case of violation of this rule, the Company may discontinue service, or require the customer to modify the installation and/or equip it with approved controlling devices.

13.3 TYPE OF INSTALLATIONS. Motor and other installations connected to the Company's lines must be of a type to use minimum starting current and must conform to the requirements of the Company as to wiring, character of equipment, and control devices.

13.4 UNBALANCED LOAD. The customer shall at all times take, and use, energy in such manner that the load will be balanced between phases to within nominally 10%. In the event of unbalanced polyphase loads, the Company reserves the right to require the customer to make the necessary changes at the customer's expense to correct the unsatisfactory condition, or to compute the demand used for billing purposes on the assumption that the load on each phase is equal to that on the greatest phase.

13.5 ADDITIONAL LOAD. The service connection, transformers, meters and equipment supplied by the Company for each customer, have definite capacity, and no additions to the equipment or load connected thereto will be allowed except by consent of the Company.

13.6 CHANGE OF INSTALLATION. The customer shall give immediate written notice to the Company of any proposed increase or decrease in, or change of purpose or location of, the installation.

13.7 FAILURE TO GIVE NOTICE. Failure to give notice of additions or changes in load or location shall render the customer liable for any damage to the meters or their auxiliary apparatus, or the transformers, or wires, of the Company, caused by the additional or changed installation.

14. METERING

14.1 SUPPLY OF METERS. An EGS that is also an AMSP may provide Advanced Meter Services in accordance with the Electric Generation Supplier Coordination Tariff. Otherwise, subject to Rules 14.3 and 14.9, the measurement of service for billing purposes shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment to be used for meters supplied by the Company, and may, from time to time, change or alter the equipment, its sole obligation being to supply meters that will accurately and adequately furnish records for billing purposes. In fulfilling its obligations with respect to metering and meter reading, and with respect to AMSPs that provide Advanced Meter Services, the Company will comply with Electric Generation Supplier Coordination Tariff.

14.2 SPECIAL MEASUREMENTS. The Company shall have the right, at its option and its own expense, to place demand meters, reactive-component meters, or other instruments, on the premises of any customer except for any customer for whom an AMSP is providing Advanced Meter Services, for the purpose of measuring the demand and/or the power factor, or for other tests of all, or any part, of the customer's load.

14.3 CUSTOMER REQUEST FOR SPECIAL METER. If a customer for whom the Company is providing either metering and meter reading wishes to replace its billing metering equipment, to the extent technically possible, the Company may offer, provide and support a selection of qualified meters and may perform installation within a reasonable amount of time and at the expense of the customer. The customer must pay for any such metering equipment based on the net incremental cost of purchasing and installing the new metering equipment as approved by the Commission. The Company will own and maintain all such new metering equipment.

RULES AND REGULATIONS (continued)

14.4 POWER FACTOR MEASUREMENT. For customers for whom the Company is providing metering and meter reading or Advanced Meter Services, the Company reserves the right to measure the power factor of the customer's load, either by test or by permanently installed instruments. For customers for whom an AMSP is providing Advanced Meter Services, the Company reserves the right to require such AMSP to measure the power factor of the load of the customer on the same basis the Company measures the power factor of customers for which the Company provides metering and meter reading or Advanced Meter Services.

14.5 REVERSE REGISTRATION. The Company may, by ratchet or other device, control its meters to prevent reverse registration.

14.6 ESTIMATED USAGE. The kilowatt-hours and billing demands to be paid for may be determined by computation instead of by measurement in the case of installations having a fixed load or demand value controlled to operate for a definite number of hours each day.

14.7 METER READING INTERVALS. The Company will read its meters in accordance with Appendix C to the Joint Petition for Full Settlement and at scheduled regular intervals of one month. Monthly customer usage will not be prorated for seasonality. For customers for whom it provides Consolidated EDC Billing or Separate EDC Billing, the Company will render standard bills for the recorded use of service based upon the time interval between meter readings. EGS & EDC charges shall be based on the EDC defined meter reading route schedules. Only those bills which cover a period of service of less than 26 days or more than 35 days will be prorated. The Company will reflect multiple supplier switches within a single monthly bill to ensure a customer can switch their electric service in accordance with the accelerated switching process final omitted rulemaking order that amends 52 Pa. Code, Ch. 57.172 – 57.179. See Dockets No. L-2014-2409383 and P-2014-2446292.

14.8 ESTIMATED USAGE. For customers for whom the Company provides meter reading or Advanced Meter Reading Services, the Company shall estimate the amount of service supplied to premises where access to the meter is not available or if such estimate is necessary, and to installations at remote locations when warranted by the type of installation, regularity of usage, or other circumstances. For customers for whom it provides Consolidated EDC Billing or Separate EDC Billing, the Company will render bills in standard form based on such estimate and so marked, for the customer's acceptance. Meter readings will be secured from time to time and billing will be revised when they disclose that the estimate failed to approximate the actual usage. For residential customers, an actual meter reading will be obtained at least every six months in accordance with Commission regulations.

14.9 CUSTOMER SELECTED ADVANCED METERS. A customer may request either PECO Energy or an AMSP to have an Advanced Meter installed and have Advanced Meter Services provided pursuant to Appendix C of the Joint Petition for Full Settlement and any applicable rules adopted by the Commission. For an advanced meter to be deployed in the PECO Energy service territory, it must be included in the Commission's Advanced Meter Catalog, and indicated as eligible for deployment in the PECO Energy territory.

14.10 MANUAL METER READING FEE Upon customer request, the Company will secure an in-person meter reading to confirm the accuracy of an automatic meter reading when a customer disconnects service or a new service request is received. The fee is $45 and the Company will include this fee on the customer's or applicant's bill.

15. DEMAND DETERMINATION

15.1 MEASURED DEMANDS. Measured demands may be quantified by recording or indicating instruments showing, unless otherwise specified, the greatest 30-minute rate-of-use of energy, provided that in the case of hoists, elevators, welding machine, electric furnaces, or other installations where the use of electricity is intermittent or subject to violent fluctuation the demand may be fixed by special determination.

15.2 DEMAND DETERMINATION.

(a) Special Determination. Where charges specified in this Tariff are based upon the customer's demand, it is intended that such demand shall fairly represent the customer's actual demand that the Company must stand ready to serve. In the case of installations where the customer's regular use of service in the ordinary course of the customer's business is such that measurement over a thirty-minute interval does not result in a fair or equitable measure of the customer's demand, then the demand may be estimated from the known character of use and the rating data of the equipment connected, or from special tests. The intent of this provision is that the demand so determined shall fairly represent the demand that the Company must stand ready to serve.

(b) Demand Waiver. When a customer wishes to conduct a test of equipment or process that is not part of the customer's normal operations, the customer may request that the Company waive the demand caused by that test, if that demand is the highest measured demand in the billing month. The Company will agree to such a waiver if the following conditions are met:

1. The Company's metering is of a type which allows for the determination of 30-minute demands; and
2. The customer's request is in writing, and is received by the Company at least 15 business days before the date of the commencement of the proposed test. The request must specify the nature of the test, the size of the loads to be tested and the starting and ending times; and
3. The Company determines that the tests are not a part of the customer's normal operations; and
4. The test will not last for more than twelve (12) consecutive hours; and
5. The customer has not conducted a test and received a demand waiver for a test pursuant to this rule within one year of the proposed test.

Upon receipt of a request for a demand waiver, the Company will inform the customer in writing within fifteen (15) days of receipt of the customer's request whether it will grant the proposed waive

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RULES AND REGULATIONS (continued)

15.3 POWER FACTOR ADJUSTMENT.

A. Standard Power Factor Values (based on measured demands)

Measured Demands (Kw)	Standard Power Factor
0 -185	80%
186 - 2,500	90%
Over 2,500	95%

B. Adjustment to Measured Demand. When a customer's measured power factor is less than the standard power factor values above, the Company shall increase the customer's measured demand by the ratio of the standard power factor to the measured power factor. The Company will then use this adjusted demand as a basis for calculating the customer's billing demand in accordance with the applicable rate schedule.

C. Determining Measured Power Factor:

1) For customers with measured demands of 750 kW or greater in three consecutive months:

(a) Until metering equipment capable of continuous power factor measurement is installed, the Company shall determine measured power factor based C3 below.
(b) Once capable metering is installed, the Company shall continuously measure power factor.
i. The customer's measured power factor shall coincide with the customer's maximum measured demand.

ii, The Company in its sole judgment may discontinue continuous power factor measurement if: (1) the customer's measured demand is less than 750 kW for twelve consecutive months, or: (2) the Company determines that changes to the customer's load characteristics will result in that customer permanently reducing measured demand to less than 750 kW.

2) For customers with measured demands of less than 185 kW:

(a) If the Company in its sole judgment deems that that the power factor is likely to be less than this standard based on the customer's load, the Company shall determine measured power factor based on C3 below.
(b) Otherwise, the Company shall assume the customer's measured power factor to be the standard noted above

3) For all other customers, including those with measured demands between 185 kW and 750 kW, the Company shall determine measured power factor in one of the following ways:

(a) By test, at a time when the customer's load is at least two-thirds of the customer's maximum measured demand in the preceding eleven months.
(b) At the option of either the customer or the Company, by measurement as determined from meters installed by the Company, ratcheted to prevent reverse registration.
i. Customers requesting measurement of power factor shall be subject to a monthly meter charge determined in accordance with the cost of the meter installation. Such installation shall not be for less than one year.
ii. When meters are installed, the measured power factor shall be the power factor that is coincident with customer's maximum measured demand.

4) A customer that receives Advanced Meter Services from an AMSP is subject to these rules regarding determination of measured power factor.

16. METER TESTS

16.1 METER TESTS. The Company at its expense, will make periodic tests and inspections of its meters in order to maintain them at a high standard of accuracy.

16.2 REQUEST TESTS. The Company will make additional tests or inspections of its meters at the request of a customer or an EGS providing Competitive Energy Supply to a customer, but reserves the right to make the charge provided for in the Electric Regulations of the Pennsylvania Public Utility Commission, under conditions therein specified.

16.3 ADJUSTMENT FOR ERROR. Should any of the Company's meters become defective or fail to register correctly, the use of electricity shall be determined by a test of any such meter, or by the registration of a meter set in its place during the period next following, or by averaging the amount registered for the preceding billing period and the amount registered during not less than one week immediately subsequent to the repairs to, or change of, the meter, taking into consideration the character of use by the customer.

16.4 RESIDENCE METER ERRORS. Meter errors in the Company's meters in residence service may be determined on the basis of the registration of the corresponding period during the preceding year, if records are available and conditions of use remain the same.

16.5 ADMINISTRATION TESTS. The Company, at its own expense, will make only such tests of the Company's meters as it deems necessary for the proper administration of its rates, or as are required by law.

16.6. TESTING SERVICE. The Company will, upon request by the customer, make tests of the Company's meters to supply special information regarding the customer's use of service, provided that the estimated cost of such special tests shall be paid by the customer to the Company at the Company's discretion.

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RULES AND REGULATIONS (continued)

17. BILLING AND STANDARD PAYMENT OPTIONS

17.1 BILLING PERIOD. Billing for service will be based upon the amount of use and the time interval of its delivery. The customer will be billed in accordance with rule 14.7. Rate values stated for direct application to monthly billing periods will be adjusted when time elapsed between readings is substantially greater or less than a month.

17.2 BILLING OPTIONS. A customer may select one of the following three billing options as communicated to PECO by the customer's supplier: (1) Consolidated EDC Billing; (2) Consolidated EGS Billing; and (3) Separate EDC/EGS Billing, as those terms are defined herein. If a customer does not make a selection, the customer shall receive Consolidated EDC Billing. When the Company provides Consolidated EDC Billing or Separate EDC Billing, it will comply with the terms and conditions of the Electric Generation Supplier Coordination Tariff. For customers who receive both electric and gas service from the Company, the Company will issue a bill that contains charges for both of these services.

17.3 PAYMENT.

(a) The Company's bills to customers are payable upon presentation. Payment for service received must be made on or before the due date shown on the bill. The due date shall be determined by the Company and shall be not less than twenty days from the date of transmittal of the bill for Rates R, R-H, RS-2, POL and GS (excluding Summary Billing Accounts). The due date shall be not less than 15 days from the date of transmittal of the bill for all other rates, including Summary Billing Accounts. Notwithstanding the foregoing, the due date may be up to thirty days for accounts (including Summary Billing Accounts) with the United States of America, the Commonwealth of Pennsylvania, or any of their departments, political subdivisions, or instrumentalities. The Company may allow a reasonable amount of additional time for payment of bills on industrial and commercial accounts of creditworthy customers. If the due date that appears on a customer's bill falls on a Saturday, Sunday, bank holiday, or any other day when the offices of the Company which regularly receive payments are not 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.

(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. The Company will not apply late fees to Final Bills as defined in Tariff Rule 20.2. If the Company files suit to collect a delinquent balance on an account (whether active or inactive) or to ensure payment of current bills, the customer will be required to pay the Company's out of pocket court costs (including filing, service, and witness fees) as ordered by the court and such costs will be added to commercial and industrial accounts.

17.6 BUDGET BILLING.

(a) At the option of a customer receiving residential service under Rates R, R-H, RS-2, and GS, an estimated total bill for all service to be received by the customer over a twelve month period may be budgeted over the period and an average bill rendered monthly for payment each month. Any difference between the budgeted amounts so paid and the actual charges for a twelve month budget period will at the customer's option, either be amortized over the next twelve months or incorporated into the 12th month bill. Absent an indication of preference from the customer, the debit or credit will be amortized. Budget billing may be discontinued upon the customer's request at which time any difference between budget billing amounts and actual charges becomes due and payable. If a monthly budget bill is not paid, a late fee will be added to the unpaid balance of actual charges on the next billing date in accordance with Rule 17.3 and 17.5. Any such late fee will be calculated based on the lesser of budget billing arrears and actual charged arrears The Company may also arrange budget billing for creditworthy commercial and industrial customers.

(b) When the Company provides Consolidated EDC Billing, the EGS's charges will be included in the customer's Budget Billing Plan.

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RULES AND REGULATIONS (continued)

17.7 CALCULATION OF LATE FEE. Where a late fee is applicable, the amount of the late fee to be added to the unpaid balance shall be calculated by multiplying the unpaid past due balance, exclusive of any previous unpaid late fees, by the appropriate late fee rate.

17.8 TAX EXEMPTION. If a customer is tax exempt, the customer must provide a tax exempt form to PECO Energy and to its EGS, regardless of which billing option the customer chooses.

17.9 BILLING ERRORS. When the Company provides Consolidated EDC Billing, PECO Energy shall not be responsible for billing errors resulting from incorrect price information received from an EGS.

17.10 RETURNED PAYMENT CHARGE. If a check (electronic or paper) received in payment of a customer's account is returned to the Company unpaid or if upon a second attempt by the Company or its agent for payment the check is again returned unpaid, then the Company will add a returned payment charge to the customer's account in the amount of **$20.00.**

17.11 APPLICABILITY TO CUSTOMERS RESIDING AT PLACE OF BUSINESS. For purposes of all of the provisions of Rule 17, when a customer resides at a place of business or commercial establishment legitimately served pursuant to a commercial or industrial Base Rate, that is not a residential dwelling unit attached thereto, the customer is not thereby entitled to any of the protections in the Public Utility Code or the Commission's regulations implementing the Pennsylvania Public Utility Code, or to any of the provisions of these rules or this Tariff, that apply exclusively to payment terms for residential customers.

18. PAYMENT TERMS & TERMINATION OF SERVICE

18.1 NON-PAYMENT TERMINATION. When the Company is providing either Consolidated EDC Billing or Separate EDC Billing, the customer is subject to collection action, including termination of service (in accordance with the Pennsylvania Public Utility Code or the Commission's regulations, on the portion of the past due amount attributable to the Company's charges for: (1) service, (2) Energy and Capacity and (3) to Customer EGS Receivables purchased by the Company. Upon termination of service, the Company may also remove its equipment. Notice that complies with applicable Commission regulations shall conclusively be considered to be "reasonable" hereunder

18.1.1 WINTER TERMINATIONS FOR NON-PAYMENT. Consistent with 52 PA Code §56.100, The Company will take the following steps for terminations for non-payment during the winter period, defined as December 1-March 31:

A. **Low-Income Eligibility:** The Company will use financial information provided by the Customer to determine if the Customer's income is at or below 250% of the Federal Poverty Level. The Company may elect to send to the Customer an income verification form for completion and return. The Company will also accept income verification provided by Community-Based Organizations that enter into a contract with PECO to provide such income verification services.

1. Annual income may be established using verified income information for a recent one-month (nominally 30-day) period, annualized to establish an estimated annual income.
2. The Company shall not require any customers who have established income eligibility for winter termination protections within the 12 months preceding the start of the winter period to re-certify or re-verify their income for that winter period. This Company may also use this information to determine deposit requirements, payment arrangements, and eligibility for any other income-specific program.

B. **Verified Low-Income Customers:** If the Company has received verified proof that a customer's household has income at or below 250% of the Federal Poverty Level, the Company will not pursue termination of that customer for non-payment during the winter period UNLESS (A) the Company receives Commission approval to do so via a petition filed pursuant to 52 Pa. Code §56.100(g), or (B) the customer has informed the Company after submitting this verification that the household no longer has income at or below 250% of the Federal Poverty Level.

For purposes of this section, the Company will accept the following as verified proof that the household has income at or below 250% of the Federal Poverty Level:

1. Enrollment in PECO's CAP program at any time within four years prior to the issuance of the winter termination notice;
2. Receipt of a LIHEAP grant at any time within four years prior to the issuance of the winter termination notice;
3. Receipt of a MEAF grant at any time within four years prior to the issuance of the winter termination notice;
4. Income verification provided by a CBO that has contracted with PECO to provide income verification information, as long as such documentation was received within four years prior to the issuance of the winter termination notice;
5. Other verified documentation that the household's income is at or below 250% of the Federal Poverty Level, as long as such documentation was received within four years prior to the issuance of the winter termination notice;
6. Receipt of verified documentation of low-income status in response to an Income Inquiry Letter, as described in Rule D.1 below.

C. **Verified Non-Low-Income Customers:** If the Company has received verified proof that a customer's household has income of greater than 250% of the Federal Poverty Level, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.

RULES AND REGULATIONS (continued)

D. **Customers with Non-Verified Income Levels:** For all other customers, prior to proceeding with termination for non-payment, the Company will send the customer a letter (the "Income Inquiry Letter") informing the customer that the Company does not have verified income information for the customer and that the customer is subject to termination for non-payment during the winter period.

1. If the customer responds with verified income information demonstrating that the household income is at or below 250% of the Federal Poverty Level, the Company will treat that household as Verified Low-Income for purposes of winter termination;
2. If the customer responds with verified income information demonstrating that the household income is greater than 250% of the Federal Poverty Level, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.
3. If the customer fails to respond to the Income Inquiry Letter or responds without providing verified income information, the Company will attempt to contact the customer via telephone to inform the customer of their duty to provide verified income information. If contact is made and verified income information is not provided by the customer, or if contact is not made, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.

18.2 PAYMENT TERMS. When the Company is providing either Consolidated EDC Billing or Separate EDC Billing, the Company will in accordance with Pennsylvania Public Utility Law and applicable Pennsylvania Public Utility Commission Regulations and Orders, negotiate payment arrangements on the portion of the past due amount attributable to its charges for: (1) service (2) Energy and Capacity and (3) to Customer EGS Receivables purchased by the Company. However, the Company will not negotiate payment arrangements on behalf of an EGS.

18.3 TERMINATION FOR CAUSE. The Company may terminate on reasonable notice if entry to the meter or meters is refused or if access thereto is obstructed or hazardous; or if utility service is taken without the knowledge or approval of the Company; or for other violation of these Rules and Regulations and/or applicable Commission rules, including those found at Pennsylvania Public Utility Code or the Commission's regulations.

18.4 SAFETY TERMINATION. The Company may terminate without notice if the customer's installation has become hazardous or defective.

18.5 DEFECTIVE EQUIPMENT TERMINATION. The Company may terminate without notice if the customer's equipment or use thereof might injuriously affect the equipment of the Company, or the Company's service to other customers; or if a certificate of approval is refused after a re-examination of the customer's installation by a competent inspection agency authorized to perform this service in the specific locality where service is provided.

18.6 TERMINATION FOR FRAUD. The Company may terminate without notice for abuse, fraud, material misrepresentation of the customer's identity, or tampering with the connections, the Company's meters, or other equipment of the Company.

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RULES AND REGULATIONS (continued)

18.7 RECONNECTION CHARGE. If service is terminated or discontinued by reason or act of the customer, the same customer, whether an applicant or a customer as defined at 66 Pa. C.S. § 1403, shall pay a reconnection charge prior to restoration of service at the same address within twelve months after discontinuance or termination. The reconnection charges, listed below, are based on the Company's current standard schedule of reconnection fees, which include direct labor costs, contractor costs, and material/transportation costs. All theft reconnections will be completed at the premise and will not be performed remotely.

	Reconnect Fees
Electric Reconnect at the Meter	$ 75.00
Electric Reconnect at Tap	$ 260.00
Electric Reconnect - Underground dig	$ 1,650.00
Electric with dual meters	$ 100.00
Electric Remote Reconnect (one or dual meters)	$ 20.00

18.8 THEFT INVESTIGATION CHARGE. If the Company establishes that there has been confirmed active theft resulting from tampering with the Company meter on the customer's premises, and the customer is or was a customer as defined at Pa. C.S. § 1403 the customer shall pay a theft investigation charge in addition to any amount that the Company establishes is due for service used, but not registered on the Company's meter. The Company reserves the right to assess theft investigation charges as a precedent to reconnection of service as well as the right to assess a separate reconnection charge as described in Rule 18.7.

	Theft Investigation Fees
Electric Theft at Meter	$400.00

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RULES AND REGULATIONS (continued)

19. UNFULFILLED CONTRACTS

19.1 NOTICE OF DISCONTINUANCE BY CUSTOMER. Notice to discontinue service before the expiration of a contract term will not relieve a customer from any minimum, or guaranteed, payment under any contract or rate. In the case of residential customers this Rule only applies if the customer has signed an express written contract that clearly sets forth such a term and condition of service.

19.2 COMPLETION OF TERM. If, by reason of any act, neglect or default of a customer, the Company's service is suspended, or the Company is prevented from providing service in accordance with the terms of any contract it may have entered into with the customer, the minimum charge for the unexpired portion of the initial contract term shall become due and payable immediately as liquidated damages. These liquidated damages may, at the option of the Company, be offset by estimated revenues from a succeeding customer at the same location, if such exists.

20. CANCELLATION BY CUSTOMER

20.1 TERMINATION NOTICE. Customers who have fulfilled their initial contract term and wish to discontinue service from the Company must give the Company at least 7 days' written notice to that effect.

20.2 FINAL BILL. The customer is liable for service taken after notice to terminate the contract, until the meter is read and/or disconnected. The final bill for service is then due.

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RULES AND REGULATIONS (continued)

21. GENERAL

21.1 OFFICE OF THE COMPANY. Wherever, in this Tariff, it is provided that notice be given or sent to the Company, or the office of the Company, such notice, delivered or mailed, postage prepaid to any commercial office, shall be deemed sufficient, unless the Principal Office of the Company at 2301 Market Street, Philadelphia, is expressly mentioned.

21.2 NO PREJUDICE OF RIGHTS. The failure by the Company to enforce any of the terms of this Tariff shall not be deemed a waiver of its right to do so.

21.3 GRATUITIES TO EMPLOYEES. The Company's employees are strictly forbidden to demand or accept any personal compensation, or gifts, for service rendered by them while working for the Company on the Company's time.

21.4 BILLING CHANGES. Where billing changes are made as the result of an investigation made at customer's request or by routine inspection, the change of billing may be applied to the bill for the regular meter reading period preceding such investigation, and will, in any event apply to the bill for the period during which the investigation is made.

21.5 EXCEPTIONAL CASES. The usual supply of electric service shall be subject to the provisions of this Tariff; but where special service-supply conditions or problems arise for which provision is not otherwise made, the Company may modify or adapt its supply terms to meet the peculiar requirements of such case, provided that such modified terms are a rational expansion of standard tariff provisions.

21.6 ASSIGNMENT. Subject to the Rules and Regulations, all contracts made by the Company shall be binding upon, and oblige and inure to the benefit of, the successors and assigns, heirs, executors and administrators of the parties thereto.

21.7 OTHER CHARGES. The Company may, if feasible, provide and charge for services, other than those provided for in this Tariff, when requested by the customer. The Company is not obligated to provide such services. The Company will, if possible, give the customer an advance written estimate of the costs to provide the service. Costs shall include, but not be limited to, materials, supplies, labor, transportation and overhead.

21.8 TAX INDEMNIFICATION. If PECO Energy becomes liable under Section 2806(g) or 2809(c) of the Public Utility Code, 66 C.S. §§ 2806(g) and 2809(c), for Pennsylvania state taxes not paid by an Electric Generation Supplier (EGS), the non-compliant EGS shall indemnify PECO Energy for the amount of additional state tax liability imposed upon PECO Energy by the Pennsylvania Department of Revenue due to the failure of the EGS to pay or remit to the Commonwealth the tax imposed on its gross receipts under Section 1101 of the Tax Reform Code of 1971 or Chapter 28 of Title 66.

22. RULES FOR DESIGNATION OF PROCUREMENT CLASS

22.1 DESIGNATION OF PROCUREMENT CLASS

a) Annually, in November the Company shall notify the customer of their procurement group class designation which shall be effective the following June 1.
b) The procurement class designation shall be used to determine the appropriate Generation Supply Adjustment to apply to the customer.
c) For non-residential customers, the procurement class shall be determined based upon the customers peak measured demand in the prior June-May period.
d) There shall be three procurement class designations. They are:
   1)Residential
   2)Small Commercial and Industrial up to and including 100 kW
   3)Large Commercial and Industrial greater than 100 kW
e) Procurement class designation shall only change once per year on the date established in rule 22.1a
f) A new customer in a new facility shall be assigned to a procurement class based upon an engineering estimate of the customer's diversified peak demand.
g) A new customer in an existing facility shall be assigned to the same procurement class as the last customer in that facility unless the new customer will use the existing facility in a substantially different manner.

RULES AND REGULATIONS (continued)

23. EGS SWITCHING

23.1 PECO Energy will accommodate requests by customers to switch EGSs on active accounts and pending active (Instant Connect) accounts in accordance with this Rule 23, Commission Order M-2014-2401085, and other applicable Commission Orders.

23.2 To switch to a new EGS, a customer must inform the new EGS. Customers that wish to switch are not required to contact PECO Energy to initiate a switch; PECO Energy will only switch a customer in accordance with Rule 23.

23.3 To enable a new EGS to complete a switch, a customer must provide to the new EGS the customer's PECO Energy Electric Choice ID number as it appears on the customer's PECO Energy monthly bill.

23.4 If a Customer contacts the Company to discontinue electric service and indicates that the Customer will be relocating outside of the Company's service territory, the Company will notify the current EGS of the Customer's discontinuance of service for the account at the Customer's location. If relocating within the Company's service territory the Company will seamlessly move the current EGS to the new location if all qualifications are met in accordance with PUC Order M-2014-2401085.

23.5 A switch to an EGS will be effective 3 business days after the enrollment request is processed, provided the enrollment request includes valid customer information as required by the controlling provisions of the Supplier Tariff. Upon receiving valid notice to switch an EGS, the Company shall notify the customer's existing EGS that such a request has been made.

23.6 If and when a customer's EGS discontinues its supply in the event of bankruptcy, loss of license, or similar occurrence, or if a Customer is dropped by its EGS for non-payment or other reason then the customer may select a new EGS. The customer will receive its energy supply from PECO Energy until the switch becomes effective.

23.7 Nothing in this Rule 23 shall be interpreted to preclude EGSs from entering into agreements for supply with a term of service of one month. EGSs may enter into agreements for longer.

23.8 The Company will send Release of Information packets to all new customers (except for customer with demands greater than 500kW), which information will provide customers the opportunity to authorize the release of their confidential account information. PECO annually notifies customers that they can change this authorization. Every three years, in accordance with PUC Docket No. M-2010-2183412, PECO will re-solicit its entire customer base (except for customer with demands greater than 500kW) for the purpose of opting out of disclosing information.

24. LOAD DATA EXCHANGE

24.1 PECO Energy will provide to a customer or the customer's designated EGS or authorized consultant, all available data from the meter once each calendar year for no fee. The exchange of data among PECO Energy, EGSs, and customers shall be in accordance with the Supplier Tariff and the Final Consensus Plan for Electronic Data Exchange Standards for Electric Deregulation in the Commonwealth of Pennsylvania, as approved by the Commission.

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STATE TAX ADJUSTMENT CLAUSE

In addition to the net charges provided for in this tariff, a **credit** value of 0.04% will apply to all PaPUC jurisdictional distribution charges in the Base Rates and Riders, effective January 1, 2024.

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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INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE EXPENSE (ICUS)

Purpose: The purpose of this surcharge is to refund to customers amounts of incremental COVID-19 related uncollectible accounts embedded in PECO's current rates.

Applicability: The surcharge shall be calculated to the nearest one-hundredth of a cent for billing purposes for all R and RH customers, for customers on all other rates it shall be the nearest one cent. The ICUS will become effective upon the effective date of rates for the electric distribution base rate case at Docket No. R-2024-3046931 for a period of one year. The ICUS shall be credited to each rate schedule as follows:

Rate R	$(0.00313)/kWh
Rate RH	$(0.00274)/kWh
Rate GS	$(0.13)/billed kW
Rate PD	$(0.08)/billed kW
Rate HT	$(0.05)/billed kW
Rate EP	$0.00/billed kW
Rate SL-E	$0.00/location
Rate SL-C	$0.00/location
Rate TLCL	$(0.01)/location
Rate AL	$0.00/location
Rate POL	$(0.28)/lamp
Rate SL-S	$(0.41)/lamp

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

Calculation of ICUS:

Billing Provisions: The credit was calculated by rate schedule using the following formula:

$$\text{ICUS} = \frac{R(n)}{BU(n)}$$

R(n) - The total amount to be refunded to customers by rate class.

BU(n) – The total estimated annual Billing Units for the rate class during the projected period when rates will be in effect.

Filing and Reconciliations: The ICUS will be reconciled at the end of the recovery period above. A final reconciliation statement will be filed within 30 days after completion of the final over/under collection refund/recovery. The Company may file interim rate adjustments to eliminate any over or under recovery of the surcharge. Such adjustments would be filed on at least 10 days' notice. The ICUS revenues and reconciliation will be subject to audit by the Commission's Bureau of Audits.

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FIBER AFFILIATE REVENUE SURCHARGE (FARS)

Purpose: The purpose of this surcharge is to refund to customers amounts for network fees that the Company collected from former affiliates for use of its fiber network.

Applicability: The surcharge shall be calculated to the nearest one-hundredth of a cent for billing purposes for all R and RH customers, for customers on all other rates it shall be the nearest one cent. The FARS will become effective upon the effective date of rates for the electric distribution base rate case at Docket No. R-2024-3046931 for a period of one year. The FARS shall be credited to each rate schedule as follows:

Rate R	$(0.00072)/kWh
Rate RH	$(0.00074)/kWh
Rate GS	$(0.13)/billed kW
Rate PD	$(0.12)/billed kW
Rate HT	$(0.07)/billed kW
Rate EP	$(0.07)/billed kW
Rate SL-E	$(0.08)/location
Rate SL-C	$(0.07)/location
Rate TLCL	$(0.13)/location
Rate AL	$(0.03)/location
Rate POL	$(5.22)/lamp
Rate SL-S	$(7.67)/lamp

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

Calculation of FARS:

Billing Provisions: The credit was calculated by rate schedule using the following formula:

$$\text{FARS} = \frac{R(n)}{BU(n)}$$

R(n) - The total amount to be refunded to customers by rate class.

BU(n) – The total estimated annual Billing Units for the rate class during the projected period when rates will be in effect.

Filing and Reconciliations: The FARS will be reconciled at the end of the recovery period above. A final reconciliation statement will be filed within 30 days after completion of the final over/under collection refund/recovery. The Company may file interim rate adjustments to eliminate any over or under recovery of the surcharge. Such adjustments would be filed on at least 10 days' notice. The FARS credits and reconciliation will be subject to audit by the Commission's Bureau of Audits.

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¶
To pass the 2018 effects of the Tax Cuts and Jobs Act ("TCJA") to customers, the FTAC will apply a negative surcharge to all PaPUC jurisdictional distribution charges, on a bills-rendered basis beginning on January 1, 2019. This FTAC will be provided through a separate mechanism showing a line item on customer bills (e.g., Federal Tax Adjustment Credit – "FTAC").¶
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 total amount of 2018 benefits to be refunded to customers. The amount being refunded will include interest accrued in 2018 using the residential mortgage lending rate specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, et seq.). No interest will be paid to customers on any amount of TCJA savings held by the Company in 2019 and refunded to customers.¶
¶
PECO will calculate the FTAC as follows, subject to reconciliation of revenues credited under the FTAC and the Company's actual 2018 TCJA savings after the end of the refund period: ¶
For residential, small commercial, and streetlighting customers (Rates R, RH, GS, SL-S, POL, AL, TLCL, SLE), PECO refunded the 2018 TCJA savings by applying the negative surcharge to bills rendered over a one-month period in January of 2019.¶
As of January 1, 2021, the FTAC will be set to: ¶
¶
Rates R,
RH: 0.00% ¶
Rates GS,
POL: 0.00% ¶
Rates AL, TLCL, SLE, SLC,
SLS: 0.00% ¶
¶
For large commercial and industrial customers (Rates HT, PD, EP), PECO refunded the 2018 TCJA savings by applying the ¶ negative surcharge to bills rendered over a one-year period, effective January 1, 2019 through December 31, 2019. As of ¶
January 1, 2021, the FTAC will be set to: ¶
¶
¶
Rates HT, PD, EP:
0.00% ¶
The FTAC will be reconciled at the end of the recovery periods above. The Company may file interim rate adjustments to eliminate any over or under recovery of the surcharges outside of their respective filing periods. Such adjustments would be filed on at least 10 days' notice.¶
A final reconciliation statement will be filed within 30 days after completion of the final over/under collection refund/recovery. The FTAC revenues and reconciliation will be subject to audit by the Commission's Bureau of Audits.¶
The FTAC will not be included in the calculation of the Distribution System Improvement Charge (DSIC).g¶

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

Applicability: June 1, 2021 this adjustment shall apply to all customers taking default service from the Company with demands up to 100 kW. The rate contained herein shall be calculated to the nearest one thousandth of a cent. The GSA shall contain the cost of generation supply for each tariff rate. The Company will apply Standard Pricing unless customers voluntarily request and are eligible to participate in the Time-Of-Use Pricing Option as detailed below.

Standard Pricing: Standard Pricing provides default service to customers who have not selected or are not eligible for PECO's Time-Of-Use Pricing Option. The rates below shall include the cost of procuring power to serve the default service customers including the cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The standard pricing for default service will represent the estimate of the cost to serve the specific tariff rate for the next quarterly period beginning with the three months ended August 31, 2021. The rates in this tariff shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2021 and are not prorated. If the balance of over/(under) recovery gets too large, the Company can file a reconciliation that will mitigate the subsequent impact. The standard generation service charge shall be calculated using the following formula:

Standard GSA(n) = (C-E+A)/S*1/(1-T)* (1-ALL)/(1-LL) +AEPS/S*1/(1 - T) + WC where;

C= The sum of the amounts paid to the full requirements suppliers providing the power for the 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 = $0.00021/kWh to represent the cash working capital for power purchases.

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges. In general, the line loss adjustment is applicable to Procurement Class 2 only as those classes contain rate classes with three different line loss factors: Current Charges:

Standard Rate		Standard GSA Price
R	GSA (1)	$0.08568
RH	GSA (1)	$0.08568
GS	GSA (2)	$0.07800

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

PD	GSA (2)	$0.07665
HT	GSA (2)	$0.07351
POL*	GSA (2)	$0.07316
SL-S*	GSA (2)	$0.07316
TLCL	GSA (2)	$0.07800
SL-E*	GSA (2)	$0.07316
AL*	GSA (2)	$0.07316
SL-C*. **	GSA (2)	$0.07316

* Prices shall exclude capacity from the Procurement Class 2 RFP results.
** Rate SL-C was effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164

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

Time-Of-Use (TOU) Pricing Option: The TOU Pricing Option provides eligible customers with an opportunity to shift energy usage away from peak periods, when wholesale electricity demand and prices are high, to off-peak periods, when demands and prices are lower. Customers may voluntarily request this option in lieu of Standard Pricing described above and must meet the TOU Eligibility Requirements below. (Customers electing this option are billed based on interval-metered consumption of usage within each TOU Pricing Period. Beginning and ending reads are not applicable TOU billing determinants.) Commencing September 1, 2021, TOU Pricing Option rates will be updated quarterly in concurrence with the Standard GSA on June 1, September 1, December 1 and March 1 and are not prorated.

The year-round TOU Pricing Periods, TOU Period Allocators ["PA-GSA(n)"], and TOU Pricing Multipliers ["PM-GSA(n)"] from June 1, 2023 through May 31, 2024 are as follows:

TOU Pricing Period	Days/Hours Included	TOU Period Allocator PA-GSA(1)	TOU Period Allocator PA-GSA(2)	TOU Pricing Multiplier PM-GSA(1) (Ratio to Super Off-Peak)	TOU Pricing Multiplier PM-GSA(2) (Ratio to Super Off-Peak)
Peak ("PP")	2:00 – 6:00 p.m. Monday through Friday, excluding PJM holidays	12%	14%	7.21-to-1	5.56-to-1
Super Off-Peak ("SOPP")	Midnight (12 a.m.) – 6 a.m. Every day	20%	20%	1-to-1	1-to-1
Off-Peak ("OPP")	All other hours	68%	66%	1.46-to-1	1.55-to-1

Commencing with the GSA and TOU rates effective June 1, 2022, PECO may update the TOU Pricing Multipliers in the above table annually, using a rolling five years of historical PJM Day-Ahead Spot Market Pricing energy data and Reliability Pricing Model capacity pricing data for the PECO zone. PECO will **only** update the applicable TOU Pricing Multipliers if the use of such data would result in no more than a 10% change from the prior-year's TOU Pricing Multipliers. If these updates would exceed 10%, the applicable TOU Pricing Multipliers will be changed by exactly 10%.

To calculate the quarterly TOU Pricing Option rates, the Company will first calculate the quarterly TOU Super Off-Peak Price ("SOPP") in accordance with the formula set forth below:

TOU SOPP GSA(n) = Standard GSA(n) * [1 / SOPP-F(n)] where;

Standard GSA(n) = Defined as above for Standard Pricing.

SOPP-F(n) = Super Off-Peak Price Factor representing the ratio of the Standard GSA(n) to the Super Off-Peak Price, calculated as follows:

TOU SOPP PA-GSA(n) + [(TOU OPP PM-GSA(n) * TOU OPP PA-GSA(n)] + [(TOU PP PM-GSA(n) * TOU PP PA-GSA(n)]

The Company will then calculate the quarterly TOU Peak ("PP") and Off-Peak ("OPP") prices as follows:

TOU PP GSA(n) = TOU SOPP GSA(n) * TOU PP PM-GSA and;

TOU OPP GSA(n) = TOU SOPP (GSA(n) * TOU OPP PM-GSA.

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

Current TOU Pricing Option Charges:

TOU Rate	Peak ("PP") (2-6 PM Monday-Friday, excluding holidays)	Super Off-Peak ("SOPP") (12-6 AM all days)	Off-Peak ("OPP") (All other times)
R (GSA 1)	$0.30015	$0.04163	$0.06078
RH (GSA 1)	$0.30015	$0.04163	$0.06078
GS (GSA 2)	$0.21673	$0.03898	$0.06042
PD (GSA 2)	$0.21300	$0.03831	$0.05938
HT (GSA 2)	$0.20427	$0.03674	$0.05695

TOU Eligibility Requirements and Switching Rules:

The TOU Pricing Option is available to new and existing Customers in Procurement Classes 1 or 2 with a smart meter configured to measure energy consumption in watt-hours. This includes Customers in the above referenced Procurement Classes taking default service from the Company and who also participate in the Company's RS-2 (Net Metering) tariff, except for virtual net metered Customers. Residential Customers enrolled in the Company's Customer Assistance Program (CAP) are not eligible for the TOU Pricing Option.

As a prerequisite for enrollment, the Customer must have a valid e-mail address to ensure the Company is able to provide the enrolled TOU Pricing Option Customer with timely and meaningful communications regarding their bill savings performance.

Participating Customers will remain on the TOU Pricing Option rate until they affirmatively elect to return to PECO's Standard GSA rate, switch to an EGS, or otherwise become ineligible.

Customers who select the TOU Pricing Option may leave at any time without incurring related penalties or fees. However, Customers who select and subsequently leave the TOU Pricing Option for any reason may not re-enroll on the TOU Pricing Option rate for twelve billing months after switching off the TOU Pricing Option rate.

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

Applicability: June 1, 2021 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, 2021 and are not prorated. If the balance of over/(under) recovery gets too large due to billing lag, the Company can file a reconciliation that will mitigate the subsequent impact. The cost for this hourly service rate shall be as follows:

Generation Supply Cost (GSC) = (C+R+AS+AC-E)/(1-T)+WCA where;

C = The PJM day ahead hourly price multiplied by the customers usage in the hour summed up for all hours in the month

$$\Sigma PJM_{DA} \text{ x usage} / (1\text{-LL})$$

PJM_{DA} – PJM on day ahead hourly price.
Usage - Electricity used by an end use customer.
R = The PJM reliability pricing model (RPM) charge for month for the customer. The RPM charge shall be the customers peak load contribution as established for PJM purposes multiplied by the current RPM monthly charge and the PJM established reserve margin adjustment.
PLC x (1+ RM) x P_{RPM} x Bill Days
PLC = Peak load contribution
RM = Reserve margin adjustment per PJM
P_{RPM} = Capacity price per MW-day
AC = Administrative Cost - This includes an allocation of the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the plan, and any other costs associated with designing and implementing a procurement plan divided by the total default service sales and then multiplied by the customers usage for the month. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.
A / S x Usage
A = Administrative cost
S = Default service sales
AS = The cost, on a $/MWH basis, of acquiring ancillary services from PJM and of complying with the Alternative Energy Portfolio Standard, multiplied by the customers usage for the month and divided by (1-LL). Congestion charges including the proceeds and costs from the exercise of
Auction Revenue Rights shall be included in this component. Ancillary services shall be those included in the Supply Master Agreement as being the responsibility of the supplier.

$$((PJM_{AS} \text{ x Usage}*1/(1\text{-LL}) + AEPS/S_{AEPS} \text{ x Usage})$$

PJM_{AS} = $/MWH charged by PJM for ancillary services
AEPS = Cost of complying with the alternative energy portfolio standard
S_{AEPS} = Sales for which AEPS cost is incurred
If the supplier provides the ancillary services and AEPS cost then the customer shall be charged the supplier's rate for these services times usage and divided by (1-LL).

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges
LL = Line loss factor as provided in the Company's Electric Generation Supplier Coordination Tariff Rule 6.6 based upon the customers distribution rate class adjusted to remove losses included in the PJM LMP
T = The currently effective gross receipts tax rate
E = $\Sigma O/(U)/S_{3/4}$ x usage where
E (Purchased Generation Adj.) = Over/under recovery as calculated in the reconciliation
$S_{3/4}$ = Procurement class 3/4 sales
WC = $0.00021 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)	$0.00932	$0.00916	$0.00881	$0.00881

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

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RECONCILIATION

Applicability: June 1, 2021 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, 2020 through December 31, 2020, reconciliation period. 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. Any over/(under) recovery shall be collected after the occurrence of two months from the end of the reconciliation period. Recovery shall be over a six month period commencing September 1 and March 1. The initial six month period is March 1, 2021 through August 31, 2021. For purposes of this rider the reconciliation shall be calculated 45 days before the effective date of recovery. The over or under recovery shall be calculated using the formula below. The calculation of the over/(under) recovery shall be done separately for the following procurement classes – Class 1 – Residential, Class 2 – Small C&I up to and including100 kW, and Class 3/4 – Large C&I greater than 100 kW. For Procurement Classes 1 and 2, Standard Pricing and TOU Pricing Option revenue and cost of supply will be included for the entire Procurement Class.

Reconciliation Formula

$E_N = \Sigma O/(U) + I$

Migration Provision $E_M = [\Sigma O/(U) + I]/S/(1\text{-}GRT)*(1\text{-}ALL)/(1\text{-}LL)$

Where:

E = Experienced over or under collection plus associated interest

N = Procurement class

M = Migration Rider

O/(U) = The monthly difference between revenue billed to the procurement class and the cost of supply as described below in Cost, AEPS Cost and Administrative Cost.

Revenue = Amount billed to the tariff rates applicable to the procurement class including approved Real Time Price or other time sensitive rates for the period being reconciled through the GSA.

Cost = The sum of the amounts paid to all of the full requirements suppliers providing the power for the period being reconciled, the spot market purchases for the period being reconciled, plus the cost of any other energy acquired for the period being reconciled. Cost shall include energy, capacity and ancillary services as well as the proceeds and costs of auction revenue rights for Procurement Classes 1 and 2. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as those costs listed in the Supply Master Agreement as the responsibility of the seller.

AEPS = The total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the Cost component above for the reconciliation period for Procurement Classes 1 and 2 and not included in the ancillary services component for Procurement Class 3/4 Hourly Service. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

Administrative Cost = This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the strategy, and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or approved in its Act 129 filing. Administrative Costs also includes other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGS's or through another rate.

Full Requirements Supply = A product purchased by the Company that includes a fixed price for all energy consumed. The only cost added by the Company to the full requirements price is for gross receipts tax, distribution line losses, and administrative cost.

Ancillary Services = The following services in the PJM OATT- reactive support, frequency control, operating reserves, supplemental reserves, imbalance charges, PJM annual charges, any PJM assessment associated with non-payment by members, and any other load serving entity charges not listed here but contained in Exhibit D of the Supply Master Agreement. Also included shall be the proceeds and costs from the exercise of auction revenue rights for Procurement Class 3/4 Hourly Service.

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RECONCILIATION
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Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges.

Capacity = The amount charged to PECO by PJM for capacity for its default service load under the reliability pricing model (RPM).

I = interest on the over or under collection at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal in accordance with the Order at Docket No. L-2014-2421001.

S= Estimated default service retail sales in kWh for the period the cost of which is being reconciled.

ALL = The average line losses in a procurement class as a percent of generation.

LL = The average line losses for a particular rate (e.g. HT, PD, GS) as provided in the Electric Generation Supplier Coordination Tariff rule 6.6.

GRT = The current gross receipts tax rate.

Procurement Class - Set of customers for which the company has a common procurement plan.

Procedural Schedule
The Company shall file the calculation of the over/under collection for the period being reconciled and the proposed adjustment to the GSA 45 days before the effective date as described below. The over/under collection adjustment shall be effective no earlier than the first day of the month such that the commencement of recovery shall lag by two months. The GSA will be effective June 1, September 1, December 1 and March 1 commencing June 1, 2021 with over/under collection recovery occurring over the six month period beginning September 1 and March 1. The data provided in the reconciliation shall be audited on an annual basis by the PaPUC Bureau of Audits.

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NUCLEAR DECOMMISSIONING COST ADJUSTMENT CLAUSE (NDCA)

The NDCA provides for the recovery of nuclear of decommissioning costs related to the Company's Ownership interest in Nuclear Generation as of 12/31/99. The NDCA shall be charged to all customers taking service under this Tariff. The adjustment shall be a cents per kWh charge calculated to the nearest one hundredth of one cent.

The Company's Ownership interest in nuclear generation as of December 31, 1999 consists of the following:

Peach Bottom 1	100%
Peach Bottom 2	42.49%
Peach Bottom 3	42.49%
Salem 1	42.59%
Salem 2	42.59%
Limerick 1	100%
Limerick 2	100%

Formula

The following formula shall be used to determine the NDCA.

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

Where:

PaPUC Authorized Decommissioning Expense Adjustment (Adjusted Annual Accrual - Base Accrual) x .95 = the Adjusted Annual Accrual in the Calculation Year less the Base Accrual. As of January 1, 2023, the NDCA shall be a credit value of ($0.0006)/kWh and will be added to the Variable Distribution Charge for all rates except for rates POL, SL-S and AL which will have a credit value of ($0.04)/location added to the Distribution Charge.

Total Pennsylvania Retail Jurisdictional Sales = total kWh sales under this Tariff for the calculation year including sales for distribution.

Calculation Year = year in which the Company proposes a change to the NDCA. To the extent a new cost study, performed every five years, indicates the Company requires an adjustment in the rate, the Company shall change the NDCA to reflect such new expense level. In calculating the annual expense, the Company shall use the sinking fund methodology.

Adjusted Annual Accrual = accrual necessary to fund the Adjusted Obligation.
Adjusted Obligation = Gross Decommissioning Obligation reduced by $50 million for ratemaking purposes.
Gross Decommissioning Obligation – The total decommissioning cost obligation as approved by the Commission as expressed in escalated future dollars.

Methodology for Calculating Expense

The base period expense shall be based upon the decommissioning costs set forth in the table below. The Company shall use a sinking fund methodology to determine the appropriate level of decommissioning expense. The assumptions shall be consistent with NRC policy and requirements.
The Base Accrual shall consist of the following levels for each unit.

Peach Bottom 1	$4,213,220
Peach Bottom 2	0
Peach Bottom 3	0
Salem 1	0
Salem 2	0
Limerick 1	0
Limerick 2	0
Total	$4,213,220

Frequency of Calculation

The annual expense shall be recalculated every five years. The Company shall adjust the NDCA to reflect the new expense level 60 days after filing the new study and the associated rate calculation with the PaPUC. The first calculation of the NDCA shall be considered to have taken place on January 1, 1998.

Completion of Decommissioning

In the event that the actual expenditures necessary to accomplish full decommissioning of the PECO Interest are less than the full balance in the funds established for such purpose, PECO shall be entitled to a release of such funds to PECO for the purpose of sharing the amount between ratepayers and shareholders. In the event that such release is granted, PECO's shareholders shall be entitled to retain: (1) the first $50 million of the net after-tax amount; and (2) 5 percent of the remaining net after-tax amount of the released funds.

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PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC)

Variable Distribution Service Charge rates for electric service in Residential Rate Schedule R and RH of this Tariff shall include a charge of $0.00685 per kWh for recovery of Universal Service Fund Cost (USFC), calculated in the manner set forth below pursuant to Section 2804 (8) of the Competition Act. The USFC rate for electric service shall be increased or decreased annually, to reflect changes in the level of Universal Service Fund costs, net of base rate recoveries, in the manner described below:

COMPUTATION OF USFC.
The USFC per kWh ($0.0000), shall be computed in accordance with the formula set forth below:

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

The USFC, so computed, shall be included in distribution rates charged to Customers for service pursuant to the rate schedules identified above. The amount of USFC, per kWh, will vary, if appropriate, based upon annual filings by the Company.

In computing the USFC, per kWh, pursuant to the formula above, the following definitions shall apply:

Reconcilable Customer Assistance Program (CAP) Costs – The difference between discounts provided to CAP customers (CAP revenue shortfalls) recovered through base rates and total CAP discounts, net of a 10.5% 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. This shall include expenditures for LIURP Health and Safety programming.

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. The interest calculation will not apply to LIURP amounts.

S - projected kWh of electric service to be billed under Rate R and Rate RH (exclusive of CAP Rider) during the projected period when rates will be in effect.

FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECONCILIATION.
The Company's annual USFC filing and its annual reconciliation statement shall be submitted to the Commission 120 days prior to new rates being effective January 1 of each year, or at such time as the Commission may prescribe. The USFC mechanism is subject to annual audit review by the Bureau of Audits.

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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.¶
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PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's proposed consumer education plan. The proposed plan shall consist of the cost of the consumer education plan approved in Docket M-2008-2032274 and P-2008-2062739.

Applicability: The surcharge shall be a per customer charge calculated to the nearest one cent, which shall be added to the fixed distribution rates for billing purposes for all customers. The rate shall be calculated separately for each customer class. The current Consumer Education Plan Cost for each Class 1 is a 2.0 cent charge per month for Rates R, RH and CAP, Class 2 and 3 is a 0.0 cent per month for Rate GS and for Class 4 is (1.0) cent credit per month for Rates HT and PD with an April 1, 2023 effective date.

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

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

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 competitive market such as advertising, customer notices, informational materials cost, and any other incremental cost associated with educating consumers about the market and about available mitigation programs offered by the Company less any cost covered by the Company's Paragraph 37 Funds. Costs associated with this program shall be expensed to FERC account 910. These costs shall also include the costs of providing expanded universal service program education and outreach to low and moderate income customers to recover up to $800,000 per year commencing on January 1, 2025.

MC(n) = consumer education cost per customer for customer class n including over/(under) recovery and associated interest.

E – The estimated over or (under) recovery from the prior year. The reconciliation period shall be the 12 months ended December 31

I – Interest on any over or (under) recovery balance. Interest shall be a rate of 6% and shall be calculated from the month of over or under collection to the mid-point of the recovery period.

N – Customer class where 1 = residential, 2 = C&I up to 100 kW, 3 = C&I from 100-500 kW, and 4 = C&I >500 kW

R – The total delivery service customers for the customer class for the application period where the application period shall be the 12-month period commencing annually on April 1 after the reconciliation period.

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

Filing Schedule: The estimated surcharge shall be filed by February 1 of each year to be effective on the following April 1. The application period shall be the 12 months that start the April 1 effective date of the surcharge. The Bureau of Audits shall audit the data in the surcharge on an annual basis.

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TRANSMISSION SERVICE CHARGE (TSC)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of all transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's default service load.

Applicability: The surcharge shall be assessed to all default service customers. The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation.

Billing Provisions: The surcharge shall be calculated on a semi-annual basis using the formula below:

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

TSC(n) = transmission service cost for customer class n including over or under recovery and associated interest.

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff. These costs shall include the following:

Network Integration Transmission Service costs and Non-Firm Point to Point Transmission costs. Included in the cost to be recovered is a working capital (WC) component as defined below.

Charges assessed by PJM for network service within the PECO zone. Included in such charges are costs for the base network service charge for the zone as well as any load serving entity charges assessed to PECO under the PJM OATT that are listed in PECO's Supply Master Agreement Exhibit D as the responsibility of the Buyer. Included in the cost to be recovered is a working capital (WC) component as defined below.

WC – cost for working capital associated with the purchase of transmission service from PJM at a rate of $278 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, SLC, SLS, POL, AL, TLCL (reconciled as a group)

S – Estimated default service sales for residential class and the street lighting class in the applicable application period. For the commercial and industrial class it shall be the estimated billed demand for the applicable application period. The application period will be the period when rates will be in effect.

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

Filings and Reconciliations: The Company shall submit filings 15 days prior to the start of the application period beginning June 1, 2015. Thereafter, the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year. If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class, the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1, September 1). The annual reconciliation statement will be made by December 31 each year.

Current Transmission Service Rate:

R= $.00857 per kilowatt hour
RH= $.00857 per kilowatt hour
Small C&I = $1.73 per billed transmission kW
Large C&I = $1.40 per billed transmission 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, SLC, SLS, POL, AL, TLCL (reconciled as a group)

S – Estimated distribution service sales for residential class and the street lighting class in the applicable application period. For the Small C&I class (Rate GS) it shall be the estimated billed demand for the applicable application period. For the Large C&I class (Rates PD, HT, and EP), the PJM PLC shall be used to calculate the NBT. The application period will be the period when rates will be in effect.

T – The currently effective gross receipts tax rate.

Filings and Reconciliations: The Company shall submit filings 15 days prior to the start of the application period beginning June 1, 2015. Thereafter, the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year. If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class, the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1, September 1). The annual reconciliation statement will be made by December 31 each year.

Current Non-Bypassable Transmission Rate:

R= $.00375 per kilowatt hour (D)
RH= $.00375 per kilowatt hour (D)
Small C&I = $0.86 per billed distribution kW (D)
Large C&I = $1.02 per kW based on the PJM PLC (D)
Street Lighting = $.00052 per kilowatt hour (D)

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PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS (EEPC)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's Phase IV Energy Efficiency and Conservation Program Costs (EEPC).

Applicability: The surcharge shall be a calculated for billing purposes for all customers. The EEPC shall be charged to each rate schedule using the following units:
Phase IV

Rates R, RS, RH:	$0.00232/kWh
Rates GS:	$0.00458/kWh
Rate SL-E,	($0.08)/location
Rate SL-C	($0.07)/location
Rate AL:	($0.02)/location
Rate TLCL:	($0.00081)/kWh
Rates HT, PD, EP:	$0.53/kW based on PJM Peak Load Contribution (PLC)

The Variable Distribution Service charges, for the residential rate schedules shall include the above listed EEPC surcharge. For the municipal lighting rate schedules, the applicable variable or fixed distribution service charges shall include the EEPC surcharge.

For Rate GS, the EEPC shall be recovered through a separate variable distribution charge listed on customer's bills. For Rates PD, HT and EP, a PJM PLC shall be determined in accordance with PJM rules and used to calculate the EEPC. Customer's PLC will be computed to the nearest kilowatt. The EEPC shall be recovered through a separate variable distribution charge listed on customer bills.

Calculation of EEPC Surcharge and the Over/Under Recovery:
Billing Provisions: The surcharge and over/under recovery shall be calculated by rate schedule on an annual basis using the following formulas:

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

C – The cost of the Energy Efficiency and Conservation Program includes: all expenditures, of the individual programs such as materials, equipment, installation, custom programs, evaluation measurement/verification, educating customers about availability to the extent not included in Consumer Education cost, not recovered through any separate recovery mechanism, and any other cost associated with implementation of the programs. Costs that relate to measures that are applicable to more than one rate class or that are shown to provide system-wide benefits, will be allocated to each class based on the ratio of class-specific projected program costs to the total projected program costs. The program costs are those approved by the PAPUC and audit costs for the Phase IV program ending May 31, 2026

E - The over or (under) recovery from the applicable reconciliation period. Interest will not be applied to any over/under collections.

SWE – The cost in dollars of the PaPUC's Statewide Evaluator. These costs will be reconciled separately and added to the EEPC and will not be subject to the 2% spending limit of the EE&C Plan.

PDR – The savings/costs from the portion of projected EE Peak Demand Resources (PDR) nominated into PJM's Forward Capacity Market (FCM). The Company will apply any proceeds/deficiencies from nominated PDR to the appropriate customer classes. These costs will be reconciled separately and added to the EEPC and will not be subject to the 2% spending limit of the EE&C Plan.

BU – The total Billing Units for the applicable recovery period.

T – The current Pennsylvania gross receipts tax rate included in base rates.

n - The rate class for which the EEPC is being calculated: 1 = Residential, 2 = Small C&I, 3 = LC&I, 4 = Street lighting
Residential - Rates R, RH
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP
Street Lighting – Rates SLE, SLC, AL, TLCL

Filings and Reconciliations: The estimated EEPC shall be filed by May 1 each year to be effective through May 31.
The first surcharge, effective June 1, 2021 will contain "C" and "E" factors calculated as follows: The "C–factor" will have two components; one including Phase III costs and the other including Phase IV costs. The Phase IV component will be set using projected costs for the 12 month period from June 1, 2021 through May 31, 2022. The Phase III component will be set using any Phase III costs from projects started prior to the end of Phase III, but not yet billed as of June 1, 2021. For the "E-factor" over/under rate will include the Phase III costs for the 10 month period from June 1, 2020 through March 31, 2021.

The second EEPC, effective June 1, 2022, will be calculated as follows: the "C-factor" will include Phase IV costs for the period June 1, 2022 through May 31, 2023 and the "E-factor" will include costs for 12 months comprising Phase III costs for the 2 months of April and May 2021 and Phase IV costs for the 10 months of June 1, 2021 through March 31, 2022. Subsequent EEPC's, effective June 1 each year will be calculated using a 12 month "C factor" for the period June 1 through May 31 and an "E factor" for the period of April 1 through March 31.

A reconciliation statement filing, in accordance with C.S. Title 66 §1307(e), will be made by April 30 of each year. The last Phase III only reconciliation statement will be for the 10 month period from June 1, 2020 through March 31, 2021. Phase IV reconciliation statements will be for the 12 month period April 1 through March 31 of each plan year. The first Phase IV reconciliation statement will cover the period April 1, 2021 through March 31, 2022 and include 2 months (April and May) of Phase III revenues and expenses and 10 months of Phase IV revenues and expenses (June through March). The EEPC mechanism is subject to annual audit review by the Bureau of Audits.

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PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT (TARC)¶
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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
$0.00000/kWh ¶
Rate
RH $0.00000/kWh
¶
Rate GS
$0.00000/kWh ¶
Rate POL $0.00/lamp
¶
Rate SL-
S $0.00/lamp ¶
Rate SL-E $0.00/location
¶
Rate SL-C $0.00/location
¶
Rate
AL $0.00/location
¶
Rate
TLCL $0.00/location
¶
Rates HT, PD,
EP $0.00000/kWh ¶
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¶
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:¶
¶

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

¶
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.¶
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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC)

In addition to the net charges provided for in this Tariff, a value of 0.00% will apply consistent with the Commission Order dated October 22, 2015 at Docket No. P-2015-2471423, approving the DSIC.

1. General Description

A. Purpose: To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

B. Eligible Property: The DSIC-eligible property will consist of the following:

Poles and Tower (Account 364);
Overhead conductor (Account 365) and underground conduit and conductors (Accounts 366 and 367);
Line transformers (Account 368) and substation equipment (Account 362);
Any fixture or device related to eligible property listed above, including insulators, circuit breakers, fuses, reclosers, grounding wires, crossarms and brackets, relays, capacitors, converters and condensers;
Unreimbursed costs related to highway relocation projects where an electric distribution company must relocate its facilities; and
Other related capitalized costs.

C. Effective Date: The DSIC will become effective January 1, 2016.

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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) (CONTINUED)

2. Computation of the DSIC

A. Calculation: The initial DSIC, effective January 1, 2016, shall be calculated to recover the fixed costs of eligible plant additions that have not previously been reflected in the Company's rates or rate base and will have been placed in service between September 1, 2015 and November 30, 2015. Thereafter, the DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update. Billing for the DSIC will be on a bills rendered basis. Thus, changes in the DSIC rate will occur as follows:

Effective Date of Change	Date to which DSIC Eligible Plant Additions Reflected
January 1	September - November
April 1	December - February
July 1	March - May
October 1	June - August

B. Determination of Fixed Costs: The fixed costs of eligible distribution system improvements projects will consist of depreciation and pre-tax return, calculated as follows:

1. Depreciation: The depreciation expense shall be calculated by applying the annual accrual rates employed in the Company's most recent base rate case for the plant accounts in which each retirement unit of DSIC-eligible property is recorded to the original cost of DSIC-eligible property.

2. Pre-tax return: The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Company's actual capital structure and actual cost rates for long-term debt and preferred stock as of the last day for the three-month period ending one month prior to the effective date of the DSIC and subsequent updates. The cost of equity will be the equity return rate approved in the Company's last fully litigated base rate proceeding for which a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years shall have elapsed between the entry of such a final order and the effective date of the DSIC, then the equity return rate used in the calculation will be the equity return rate calculated by the Commission in the most recent Quarterly Report on the Earnings of Jurisdictional Utilities released by the Commission.

C. Application of DSIC: The DSIC will be expressed as a percentage carried to two decimal places and will be applied to the total amount billed to each customer for distribution service and the State Tax Adjustment Surcharge (STAS). To calculate the DSIC, one-fourth of the annual fixed costs associated with all property eligible for cost recovery under the DSIC will be divided by the Company's projected revenue for distribution service (including all applicable clauses and riders) for the quarterly period during which the charge will be collected, exclusive of the STAS.

D. Formula: The formula for calculation of the DSIC is as follows:

$$DSIC = \frac{(DSI * PTRR) + STFT + Dep + e) \times 1/(1-T)}{PQR}$$

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Where:

DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation and associated accumulated deferred income taxes pertaining to property-related book/tax depreciation timing differences resulting from the use of accelerated depreciation per Internal Revenue Code, 26 U.S. Code § 168.

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

STFT = (State Tax Flow Through) Pre-tax flow through calculated on book-tax timing differences between accelerated tax depreciation and book depreciation net of federal tax. **[NOTE: UTILITY MAY ELECT TO INCLUDE STFT CALCULATION IN THE PTRR COMPONENT].**

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Dep = Depreciation expense related to DSIC-eligible property.

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

T= If applicable, Pennsylvania Gross Receipts Tax rate in effect during the billing month, expressed in decimal form.

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PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from applicable customers.

Revenue shall be based on three-month period of projected annual revenues.

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[NOTE: THE DSIC CALCULATION DOES NOT FACTOR IN THE PLANT OF ACQUIRED TROUBLED COMPANIES OR THE REVENUE OF CUSTOMERS ACQUIRED FROM TROUBLED COMPANIES UNTIL SUCH PLANT AND CUSTOMER RATES HAVE BEEN PART OF A BASE RATE CASE BY THE ACQUIRING UTILITY].

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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

3. Quarterly Updates: Supporting data for each quarterly update will be filed with the Commission and served upon the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, Bureau of Audits and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update.

4. Customer Safeguards

A. Cap: The DSIC is capped at 5.0% of the amount billed to customers for distribution service (including all applicable clauses and riders) as determined on an annualized basis.

B. Audit/Reconciliation: The DSIC is subject to audit at intervals determined by the Commission. Any cost determined by the Commission not to comply with any provision of 66 Pa C.S. §§ 1350, *et seq*., shall be credited to customer accounts. The DSIC is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year or the Company may elect to subject the DSIC to quarterly reconciliation but only upon request and approval by the Commission. The revenue received under the DSIC for the reconciliation period will be compared to the Company's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year or in the next quarter if permitted by the Commission. If DSIC revenues exceed DSIC-eligible costs, such over-collections will be refunded with interest. Interest on over-collections and credits will be calculated at the residential mortgage lending specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, *et seq*.) and will be refunded in the same manner as an over-collection. The Company is not permitted to accrue interest on under collections.

C. New Base Rates: The DSIC will be reset at zero upon application of new base rates to customer billings that provide for prospective recovery of the annual costs that had previously been recovered under the DSIC. Thereafter, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company's rates or rate base will be reflected in the quarterly updates of the DSIC.

D. Customer Notice: Customers shall be notified of changes in the DSIC by including appropriate information on the first bill they receive following any change or through an explanatory bill insert included with the first billing.

E. All customer classes: The DSIC shall be applied equally to all customer classes.

F. Earning Reports: The DSIC will also be reset at zero if, in any quarter, data filed with the Commission in the Company's then most recent Annual or Quarterly Earnings reports show that the Company would earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC as described in the pre-tax return section. The Company shall file a tariff supplement implementing the reset to zero due to overearning on one-day's notice and such supplement shall be filed simultaneously with the filing of the most recent Annual or Quarterly Earnings reports indicating that the Company has earned a rate of return that would exceed the allowable rate of return used to calculate its fixed costs.

G. Residual E-Factor Recovery Upon Reset To Zero: The Company shall file with the Commission interim rate revisions to resolve the residual over/under collection or E-factor amount after the DSIC rate has been reset to zero. The Company can collect or credit the residual over/under collection balance when the DSIC rate is reset to zero. The Company shall refund any overcollection to customers and is entitled to recover any undercollections as set forth in Section 4.B. Once the Company determines the specific amount of the residual over or under collection amount after the DSIC rate is reset to zero, the Company shall file a tariff supplement with supporting data to address that residual amount. The tariff supplement shall be served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the supplement.

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: $14.30
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $2.77

VARIABLE DISTRIBUTION SERVICE CHARGE:
All kWhs $0.10320 per kWh

ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

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

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

PAYMENT TERMS. Standard.

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RATE RH RESIDENTIAL HEATING SERVICE

AVAILABILITY.
Single phase service to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for domestic requirements when such service is provided through one meter and where the dwelling is heated by specified types of electric space heating systems. The systems eligible for this rate are (a) permanently connected electric resistance heaters where such heaters supply all of the heating requirements of the dwelling, (b) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by electric resistance heaters, and (c) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by non electric energy sources. All space heating installations must meet Company requirements. This rate schedule is not available for commercial, institutional or industrial establishments.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date, must be individually metered

CURRENT CHARACTERISTICS. Standard single phase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $14.30
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $2.77

VARIABLE DISTRIBUTION SERVICE CHARGE:
SUMMER MONTHS. (June through September)
$0.10320 per kWh for all kWh.
WINTER MONTHS. (October through May)
$0.08386 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, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND CONSERVATION PROGRAM COSTS 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. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate R, RH, or CAP) or not larger than 3,000 kilowatts at other customer service locations (Rate GS, HT, PD and EP), except for Customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers "IEEE" and the Commission.

Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rate is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

Service under this Rate is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

METERING PROVISIONS.

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, RH, CAP, GS, HT, PD or EP.

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

   Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

3. Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator's property. Meter aggregation shall only be available for properties located within the Company's service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis. Customer generators involved in virtual metering programs are not eligible for the company's default service TOU Pricing Option commencing September 1, 2021.

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RATE RS-2 NET METERING (continued)

BILLING PROVISIONS.

The following billing provisions apply to default service customer-generators in conjunction with service under applicable Rates R, RH, CAP, GS, HT, PD, EP.

1. The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If a customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours received from the customer-generator in excess of the kilowatt hours delivered by Company to the customer-generator during the preceding year at the "full retail value for all energy produced" consistent with Commission regulations. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   Commencing September 1, 2021, for default service Time-Of-Use ("TOU") customer-generators only: The Company will record excess generation supplied by TOU Pricing Period, maintaining an active record of kilowatt hours produced and consumed at the customer-generator's premise. If, in a subsequent default service TOU billing period, a customer consumes more electricity than produced within a given TOU Pricing Period, the Company will pull kilowatt hours for the excess generation from the customer's banked kilowatt-hours for that TOU Pricing Period. Any excess kilowatt hours remaining in that TOU Pricing Period will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the TOU customer generator for accumulated excess generation at the full retail value based on the applicable TOU Pricing Option rate and TSC rate in effect at the time the excess electricity was generated.

   If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

2. For customer-generators involved in virtual meter aggregation programs, any excess credit shall be applied first to the account containing the meter through which the generating facility supplies electricity to the distribution system, also known as the "host account". If the host account's usage has been fully offset by this credit and additional excess credit still remains, PECO will divide that remaining credit into equal parts based on the number of additional virtually metered accounts under the customer-generator's name, also known as "satellite accounts", and apply one part to each satellite account in a "waterfall"-like fashion at each account's designated rate. This process continues as PECO bills each subsequent satellite account, with any additional excess credits from each divided equally among the remaining satellite accounts. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. Procurement Class 3/4 customer-generators will receive a generation credit, at the PJM Day Ahead hourly energy rate, for each kilowatt hour received by the Company during each hour of the billing period up to the total amount of electricity delivered to the customer during each hour of the billing period. If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator during any hour in the billing period, the excess kilowatt hours shall not be carried forward to a subsequent billing period but will be credited in the current month toward generation charges based on the PJM Day Ahead hourly rate. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year.

4. Procurement Class 3/4 customer-generators will also receive a variable distribution credit for each kilowatt hour received by the Company during the monthly billing period up to the total amount of electricity delivered to the Customer during the monthly billing period at the applicable distribution rate.

   If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator, the variable distribution charges will be reduced by the excess kilowatt hours, which will be carried forward and credited against the customer-generator's distribution kilowatt hours in subsequent billing periods until the end of the PJM planning period, ending May 31 of each year.

   Procurement Class 3/4 customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges.

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RATE RS-2 NET METERING (continued)

NET METERING FOR SHOPPING CUSTOMERS.

1. Customer-generators may take net metering services from EGSs that offer such services.

2. If a net-metering customer takes service from an EGS, the Company will credit the customer for distribution charges for each kilowatt hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter, up to the total amount of kilowatt hours delivered to the customer by the Company during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the Company's distribution rates. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rates Schedule.

3. If the Company delivers more kilowatt hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the applicable rate schedule shall be applied to the net kilowatt hours of electricity that the Company delivered. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. Pursuant to Commission regulations, the credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS.

5. If a customer-generator switches electricity suppliers, the Company shall treat the end of the service as if it were the end of the PJM planning period.

APPLICATION.

Customer-generators seeking to receive service under the provisions of this Rate must submit a written application online to the Company demonstrating compliance with the Net Metering Rate provisions and quantifying the total rated generating capacity of the customer-generator facility. The link to the online application can be found on the Green Power Connection pages on peco.com.

INTERCONNECTION EXPIRATION.

Interconnection applications will be reviewed and processed in accordance with the timeframes designated by PECO in Act 213 and Title 52 of the Pa Code Chapter 75. A customer-generator (or authorized designee) must submit a completed certificate of completion ("COC") for residential level 1 and 2 interconnection applications to PECO within 180 calendar days from the date that PECO approves the interconnection application. If a COC is not received within 180 calendar days from the date that PECO approves the interconnection application then the residential level 1 and level 2 interconnection applications shall expire. A customer-generator may request an extension of a residential level 1 or level 2 application expiration date for good cause shown (i.e., that significant progress in construction of the interconnection has been or will be made). Upon a showing of good cause, the application expiration date will be extended. The length of the extension may be extended up to but no more than 180 calendar days. A customer-generator must make such extension requests in writing or via e-mail no less than 30 calendar days prior to an application's original expiration date. PECO will provide notice to developers of distributed generation at least 45 calendar days ahead of the original expiration date.

Any interconnection application in (a) Conditionally Approved or (b) Engineering Study status will expire in 6 months unless a customer-generator takes steps to (a) satisfy the conditions of the Conditional Approval or (b) pays for and moves forward with the Engineering Study. A customer-generator will be notified of the upcoming interconnection application expiration 45 calendar days ahead of the expiration date. Prior to the expiration of the 6-month period, a customer-generator may request an extension to resolve the outstanding issues surrounding their interconnection application. Upon a showing of good cause, the interconnection application expiration date will be extended up to but no more than 180 calendar days.

MINIMUM CHARGE.

The Minimum Charges under Rate Schedule R, RH, CAP, GS, PD, HT and EP apply for installations under this Rate.

RIDERS.

Bills rendered by the Company under this Rate shall be subject to charges stated in any other applicable Rate.

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RATE-GS GENERAL SERVICE

AVAILABILITY.
Service for offices, professional, commercial or industrial establishments, governmental agencies, farms and other applications outside the scope of the Residence Service rate schedules.

Transformed service from the Company's distribution system where the company installs, owns, and maintains any transforming, switching and other receiving equipment required.

For service configurations that are nominally 120/208 volts, 3 phase, 4 wires – If either the service capacity or the parallel-generating capacity exceeds 750 kVA for transformers located inside the building, the only rate option available to the customer will be Rate HT. If either the service capacity or the parallel-generating capacity exceeds 750 kVA but remains at or below 1,500 kVA for transformers outside the building, the customer may request service at 277/480 volts, 3-phase 4-wires from transformers located outside the building. Otherwise the only rate option available to the customer will be Rate HT.

For service configurations that are nominally 277/480 volts, 3 phase, 4 wires - If either the service capacity or the parallel-generating capacity exceeds either 750 kVA for transformers located inside the building or 1,500 kVA for transformers located outside the building, the only rate option available to the customer will be Rate HT.

CURRENT CHARACTERISTICS.
Standard single-phase or polyphase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE:
$24.47 for single-phase service without demand measurement, or
$31.20 for single-phase service with demand measurement, or
$74.66 for polyphase service.

VARIABLE DISTRIBUTION SERVICE CHARGE:
$12.10 per kW of billed demand

($0.0006) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: $0.00458 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and ¾.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand may be measured where consumption exceeds 1,100 kilowatt-hours per month for three consecutive months; or where load tests indicate a demand of five or more kilowatts; or where the customer requests demand measurement. Measured demands will be determined to the nearest 0.1 of a kilowatt but will not be less than 1.2 kilowatts, and will be adjusted for power factor in accordance with the Rules and Regulations.
For those customers with demand measurement the billing demand will be determined as follows:
(a) For customers with demand up to 500 kW, the billing demand shall be the measured demand, with a minimum billing demand of 1.2 kW.
(b) For customers with measured demand or maximum 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, plus the Variable Distribution Service Charge per KW of minimum billing demand as described above. The monthly minimum charge for customers with demand measurement will be the Fixed Distribution Service Charge, plus per KW of billing demand. In addition to the above, for customers in Procurement Class ¾ charges will be assessed on PJM's reliability pricing model.

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RATE-GS GENERAL SERVICE (continued)

SPECIAL PROVISION.

In accordance with Section 1511, Title 66 Public Utilities, a volunteer fire company, non-profit rescue squad, non-profit ambulance service or a non-profit senior citizen center meeting the requirements set forth below, may, upon application, elect to have its electric service billed at any of the following rate schedules: Rate R Residential Service or Rate R-H Residential Heating Service, as appropriate for the application. The execution of an electric service contract for a minimum term of one year at the chosen rate will be required of any entity electing service pursuant to the options provided by this provision.

For the purposes of this provision, the following words and terms shall have the following meanings, unless the context clearly indicates otherwise:

VOLUNTEER FIRE COMPANY. A separately metered service location consisting of a building, sirens, a garage for housing vehicular firefighting equipment, or a facility certified by the Pennsylvania Emergency Management Agency (PEMA) for fire fighter training. The use of electric service at this location shall be to support the activities of the volunteer fire company. Any fund raising activities at this service location must be used solely to support volunteer fire fighting operations.

The customer of record at this service location must be a predominantly volunteer fire company recognized by the local municipality or PEMA as a provider of firefighting services.

NON PROFIT SENIOR CITIZEN CENTER. A separately metered service location consisting of a facility for the use of senior citizens coming together as individuals or groups and where access to a wide range of services to senior citizens is provided. The customer of record at this service location must be an organization recognized by the Internal Revenue Service (IRS) or the Commonwealth as a non-profit entity and recognized by the Pennsylvania Department of Aging as an operator of a senior citizen center.

NON-PROFIT RESCUE SQUAD. A separately metered service location consisting of a building, sirens, a garage for housing vehicular rescue equipment; and qualified by the Commonwealth as a non-profit entity; and a facility recognized by the Pennsylvania Emergency Management Agency (PEMA) or the Pennsylvania Department of Health as a provider of rescue services. The use of electric service at this location shall be to support the activities of the non-profit rescue squad. Any fund raising activities at this service location must be used solely to support the non-profit rescue squad operations.

NON-PROFIT AMBULANCE SERVICE. A separately metered service location consisting of a building, sirens, a garage for housing vehicular rescue equipment; and qualified by the Commonwealth as a non-profit entity; and a facility licensed by the Pennsylvania Department of Health as a provider of ambulance services. The use of electric service at this location shall be to support the activities of the non-profit ambulance service. Any fund raising activities at this service location must be used solely to support the non-profit ambulance service operations.

TERM OF CONTRACT.
The initial contract term shall be for at least one year.

PAYMENT TERMS.
Standard.

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RATE-PD PRIMARY DISTRIBUTION POWER

AVAILABILITY.
Untransformed service from the primary supply lines of the Company's distribution system where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required. However, standard primary service is not available in areas where the distribution voltage has been changed to either 13 kV or 33 kV unless the customer was served with standard primary service before the conversion of the area to either 13 kV or 33 kV. This rate is available only for service locations served on this rate on July 6, 1987 as long as the original primary service has not been removed. PECO Energy may refuse to increase the load supplied to a customer served under this rate when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist. If a customer changes the billing rate of a location being served on this rate, PECO Energy may refuse to change that location back to Rate PD when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist.

CURRENT CHARACTERISTICS.
Standard primary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $297.61

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VARIABLE DISTRIBUTION SERVICE CHARGE:
$12.16 per kW of billing demand
($0.0006) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: $0.53 per kW of Peak Load Contribution

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

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DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. The 25kW minimum shall apply to the Energy Supply Charge and the Transmission Supply Charge. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract.

MINIMUM CHARGE.
The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, plus in the case of Procurement Class 3/4 customers, charges assessed under PJM's reliability pricing model.

TERM OF CONTRACT.
The initial contract term shall be for at least three years.

PAYMENT TERMS.
Standard.

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RATE-HT HIGH TENSION POWER

AVAILABILITY.
Untransformed service from the Company's standard high tension lines, where the customer installs, owns, and maintains, any transforming, switching and other receiving equipment required.

CURRENT CHARACTERISTICS.
Standard high tension service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $371.67

VARIABLE DISTRIBUTION SERVICE CHARGE:
$7.83 per kW of billing demand
($0.0006) per kWh for all kWh

HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For customers supplied at 33,000 volts: $0.26 per kW of measured demand.
For customers supplied at 69,000 volts: $2.13 per kW of measured demand.
For customers supplied over 69,000 volts: $2.13 per kW of measured demand.

ENERGY EFFICIENCY CHARGE: $0.53 per kW of Peak Load Contribution

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND CONSERVATION PROGRAM AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract. The 25 kW minimum shall apply to the Energy Supply Charge and the Transmission Supply Charge.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS.
If the load of a customer located at a delivery point becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer at that delivery point, upon the written request of the customer, the Company will establish a new delivery point and bill the customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point and provided that such multi-point delivery is not disadvantageous to the Company.

MINIMUM CHARGE.
The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, and modify less the high voltage discount where applicable plus in the case of Procurement Class 3/4 customers, charges assessed on PJM's reliability pricing model.

TERM OF CONTRACT.
The initial contract term shall be for at least three years.

PAYMENT TERMS.
Standard.

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RATE EP ELECTRIC PROPULSION

AVAILABILITY.
This rate is available only to the National Rail Passenger Corporation (AMTRAK) and to the Southeastern Pennsylvania Transportation Authority (SEPTA) for untransformed service from the Company's standard high tension lines, where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required and where the service is provided for the operation of electrified transit and railroad systems and appurtenances. Rate EP is also available to legacy transformed service that is receiving service pursuant to Rate EP as of January 1, 2020; Rate EP or successor rates shall remain available for such legacy transformed service until at least December 31, 2040.

CURRENT CHARACTERISTICS.
Standard sixty hertz (60 Hz) high tension service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $1,292.35 per delivery point

VARIABLE DISTRIBUTION SERVICE CHARGE:
$6.79 per kW of billing demand
($0.0006) per kWh for all kWh

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HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For delivery points supplied at 33,000 volts: $0.27 per kW.
For delivery points supplied at 69,000 volts: $2.17 per kW for first 10,000 kW of measured demand.
For delivery points supplied over 69,000 volts $2.17 per kW for first 100,000 kW of measured demand.

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ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class ¾.

ENERGY EFFICIENCY CHARGE: $0.53 per kW of Peak Load Contribution

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

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DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 5,000 kilowatts. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS.
If the load of a customer located at a delivery point becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer at that delivery point, upon the written request of the customer, the Company will establish a new delivery point and bill the customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point and provided that such multi-point delivery is not disadvantageous to the Company. Conjunctive billing under this section is available regardless of whether the conjunctively-billed sites take generation service from one or more generation suppliers and/or PECO default service.

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RATE POL PRIVATE OUTDOOR LIGHTING

AVAILABILITY.
To any residential or commercial customer with outdoor lighting of sidewalks, driveways, yards, lots and similar places, outside the scope of service under Rates SL-S and SL-E.

MONTHLY RATE TABLE.
A Standard Lighting Unit shall be a Cobra Head or Floodlight comprised of a bracket, the lead wires, and a luminaire, including lamp, reactor, and control. The wattage is composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls, and other load components required for its operation

MERCURY-VAPOR LAMPS	PRICE PER LIGHTING UNIT DISTRIBUTION (Co.Pole)	(Cust.Pole)
100 Watts (nominally 4,000 Lumens)	$14.28	$12.19
175 Watts (nominally 8,000 Lumens)	$21.25	$19.26
250 Watts (nominally 12,000 Lumens)	$27.42	$25.64
400 Watts (nominally 20,000 Lumens)	$36.86	$34.51
400 Watts Floodlight (nominally 22,000 Lumens)	$40.37	$38.02

SODIUM-VAPOR LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
70 Watts (nominally 5,800 Lumens)	$21.63	$19.59
250 Watts (nominally 25,000 Lumens)	$37.46	$35.11
400 Watts (nominally 50,000 Lumens)	$41.44	$39.08
400 Watts Floodlight (nominally 50,000 Lumens)	$44.92	$42.57

Service to the above listed Mercury-Vapor Lamps and Sodium-Vapor Lamps is not available as of January 1, 2016 to new Customers or existing customers for new or replacement luminaires. The Company will not replace defective or broken mercury vapor or sodium vapor luminaires, including ballasts. In such cases, the customer must take service under one of the current lighting unit options as set forth below.

METAL HALIDE LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
100 Watts (nominally 7,800 Lumens)	$34.74	$33.42
175 Watts (nominally 13,000 Lumens)	$36.70	$34.24
250 Watts (nominally 20,500 Lumens)	$39.12	$36.68
400 Watts (nominally 36,000 Lumens)	$44.16	$41.86
1000 Watts (nominally 110,000 Lumens)	$80.88	$78.64

HIGH PRESSURE SODIUM VAPOR LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
50 Watts (nominally 4,000 Lumens)	$21.46	$19.39
70 Watts (nominally 5,800 Lumens)	$25.03	$22.74
100 Watts (nominally 9,500 Lumens)	$26.72	$24.44
150 Watts (nominally 16,000 Lumens)	$29.64	$27.37
250 Watts (nominally 25,000 Lumens)	$35.65	$33.33
400 Watts (nominally 50,000 Lumens)	$44.24	$41.94
1,000 Watts (nominally 130,000 Lumens)	$51.70	$50.81

LIGHT-EMITTING DIODE LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
35 Watts (nominally 3,300 Lumens)	$38.70	$36.56
53 Watts (nominally 5,000 Lumens)	$39.79	$37.66
87 Watts (nominally 8,300 Lumens)	$41.26	$39.12
163 Watts (nominally 15,800 Lumens)	$45.35	$43.21
215 Watts (nominally 20,000 Lumens)	$47.81	$45.66

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

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, NON-BYPASSABLE TRANSMISSION CHARGE, CONSERVATION PROGRAM COSTS AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

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RATE POL PRIVATE OUTDOOR LIGHTING (continued)

TERMS AND CONDITIONS.

1. Service. Lighting service shall be supplied from distribution facilities and equipment installed, owned, and maintained by the Company. Each lighting installation must be separately connected to a Point of Delivery on the Company's secondary distribution system. Lighting service will be operated on an all-night, every-night lighting schedule under which lights are turned on after sunset and off before sunrise with approximately 4,100 operating hours (average monthly burning hours = 341.11 hours). Each lamp shall be controlled by a photoelectric cell which shall operate to energize the lamp during periods of darkness and de-energize it during other periods. The service includes the supply of lamps and their renewal when burned out or broken. Renewal of lamps will be made only during regular daytime working hours after notification by the customer of the necessity.

2. Standard Installations. In connection with the standard service provided herein, the Company will install, own and maintain all facilities within highway limits, all standard service-supply lines, and all Lighting Units. The customer will install, own and maintain all poles on the customer's property and all service extensions on the customer's property from the Company's standard service-supply lines.

Investment by the Company under standard conditions of supply will be limited to that warranted by three times the prospective revenue recovered through the Company's tariffed Variable Distribution Service Charge. Any additional investment will be assumed by the customer.

Title to all lighting installations of a type approved by the Company shall be vested in the Company and all necessary maintenance, repair and replacement of equipment in such installations will be made by the Company.

Standard supply to lighting installations will be from aerial wires, except that, at the option of the Company, in areas where its other distribution facilities are underground, supply may be underground.

3. Non-Standard installations. For underground supply furnished at the request of the customer where aerial supply would be normal, or for other than standard installations made at the request of the customer and of a type approved by the Company, the Company will assume the cost up to the amount it would normally have invested and will require the customer to contribute all excess costs.

The Company may offer non-standard Lighting Units and installations in addition to those listed above in the Monthly Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract based on the incremental cost over that listed in the Monthly Rate Table. Maintenance, repair and replacement of nonstandard equipment shall be at the expense of the customer.

(A) Location Authorization and Protection. The location of lamps to be supplied is to be approved by the properly designated authorized representative of the customer. The customer shall furnish any requisite authority for the erection and maintenance of poles, wires, luminaires and other equipment necessary to operate the lamps at the approved locations.

Lighting Units shall be installed at locations and upon structures approved by the Company and in positions permitting servicing from a ladder truck.

At the expense of the customer, the Company will relocate a lamp to a new location after receiving a written request from the customer.

The customer shall protect the Company from malicious damage to the lighting system.

Customer construction shall meet the Company's standards which are based upon the National Electrical Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work. The customer shall obtain and submit any permits or other authority requisite to the installation and operation of the Lighting Units served hereunder.

5. Equipment Removal. If the customer requests that the Company remove or replace any existing Private Outdoor Lighting installation, the Company will charge for removal or replacement of the installations and the associated poles and conductors used exclusively for the street lighting installation. The Company's charge will include the cost of removal or replacement plus the estimated remaining book value of the removed or replaced equipment less salvage.

6. Outage Allowances. Written notice to the Company prior to 4:00 pm of the failure of any light to burn on the previous night shall entitle the customer to a pro rata reduction in the charges under this rate for the hours of failure if such failure continues for a period in excess of 24 hours after the notice is received. Allowances will not be made for outages resulting from the customer's failure to protect the lighting system or from riot, fire, storm, flood, interference by civil or military authorities, or any other cause beyond the Company's control.

(B) Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each lighting unit shall be for at least three years.

PAYMENT TERMS.
Standard.

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RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES

AVAILABILITY.
To any municipal entity for outdoor lighting of streets, highways, bridges, parks and similar places located outside the city and county of Philadelphia, including directional highway signs at locations where other outdoor lighting service is established hereunder, only if all of the distribution facilities and equipment are installed, owned, and maintained by the Company.

ANNUAL RATE TABLE
The prices in the Rate Table apply to all Company-approved installations for (a) federal, state, county and municipal authorities and community associations entering into a contract for lighting service; and (b) building operation developers for lighting, during the development period, of streets that are to be dedicated, where the municipality has approved the lighting and agreed to subsequently assume the charges for it under a standard contract.

The wattage is composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls, and other load components required for its operation.

Incandescent Filament Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
320 Lumens	32	$123.88
600 Lumens	58	$176.87
1,000 Lumens	103	$249.56
2,500 Lumens	202	$345.98
6,000 Lumens	448	$394.03
10,000 Lumens	690	$477.96

Mercury Vapor Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
4,000 Lumens	115	$295.18
8,000 Lumens	191	$311.62
12,000 Lumens	275	$332.18
20,000 Lumens	429	$390.73
42,000 Lumens	768	$558.71
59,000 Lumens	1,090	$628.89

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	$293.08
9,500 Lumens	131	$319.14
16,000 Lumens	192	$359.05
25,000 Lumens	294	$408.10
50,000 Lumens	450	$487.30

Light-Emitting Diode Lamps Size of Lamp (Nominal)

	Billing Watts	Distribution
3,300 Lumens	35	$522.79
5,000 Lumens	53	$535.98
8300 Lumens	87	$553.45
15,800 Lumens	163	$602.63
20,000 Lumens	215	$632.09

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

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT, APPLY TO THIS RATE.

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RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES (continued)

TERMS AND CONDITIONS.

1. Service. Lighting service shall be supplied from distribution facilities and equipment installed, owned, and maintained by the Company. Each lighting installation must be separately connected to a Point of Delivery on the Company's secondary distribution system. Lighting service will be operated on an all-night, every-night lighting schedule under which lights are turned on after sunset and off before sunrise with approximately 4,100 operating hours (average monthly burning hours = 341.11 hours). Each lamp shall be controlled by a photoelectric cell which shall operate to energize the lamp during periods of darkness and de-energize it during other periods. The service includes the supply of Lightning Units and their renewal when burned out or broken. Renewal of lamps will be made only during regular daytime working hours after notification by the customer of the necessity.

2. Standard Installations. The Company will install, own, and maintain its distribution facilities and equipment on the public highways to the extent warranted by three times the prospective revenue recovered through the Company's tariffed Variable Distribution Service Charge, with any additional investment to be assumed by the customer.

Title to all lighting installations of a type approved by the Company shall be vested in the Company and all necessary maintenance, repair and replacement of equipment in such installations will be made by the Company.

Standard supply to lighting installations will be from aerial wires, except that, at the option of the Company, in areas where its other electric distribution facilities are underground, supply may be underground.

3. Non-Standard installations. For underground supply furnished at the request of the customer where aerial supply would be normal, or for other than standard installations made at the request of the customer and of a type approved by the Company, the Company will assume the cost up to the amount it would normally have invested and will require the customer to contribute all excess costs.

The Company may offer non-standard Lighting Units and installations in addition to those listed above in the Annual Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract based on the incremental cost over that listed in the Annual Rate Table. Maintenance, repair and replacement of nonstandard equipment shall be at the expense of the customer.

The installation cost of lighting on private property, or for contracts of less than standard term, shall be paid by the customer.

4. Location, Authorization and Protection. The location of lamps to be supplied is to be approved by the properly designated authorized representative of the customer. The customer shall furnish any requisite authority for the erection and maintenance of poles, wires, luminaires and other equipment necessary to operate the lamps at the approved locations.

Lighting Units shall be installed at locations and upon structures approved by the Company and in positions permitting servicing from a ladder truck.

At the expense of the customer, the Company will relocate a lamp to a new location after receiving a written request from the customer.

The customer shall protect the Company from malicious damage to the lighting system.

5. Equipment Removal. If the customer requests that the Company remove or replace any existing Street Lighting installation, the Company will charge for removal or replacement of the installation and the associated poles and conductors used exclusively for the installation. The Company's charge will include the cost of removal or replacement plus the estimated remaining book value of the removed or replaced equipment less salvage.

6. Outage Allowances. Written notice to the Company prior to 4:00 pm of the failure of any light to burn on the previous night shall entitle the customer to a pro rata reduction in the charges under this rate for the hours of failure if such failure continues for a period in excess of 24 hours after the notice is received. Allowances will not be made for outages resulting from the customer's failure to protect the lighting system or from riot, fire, storm, flood, interference by civil or military authorities, or any other cause beyond the Company's control.

7. Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each lighting installation shall be for at least three years.

PAYMENT TERMS.
Bills will be rendered monthly. Each month, for the purpose of prorating the price, shall be considered 1/12 of a year.

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RATE SL-E STREET LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.
To any governmental agency for outdoor lighting provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, including directional highway signs at locations where other outdoor lighting service is established hereunder only if all of the Utilization Facilities, as defined in Terms and Conditions in this Base Rate, are installed, owned and maintained by a governmental agency.

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers. All facilities and their installation shall be approved by the Company.

MONTHLY RATE TABLE.

SERVICE LOCATION DISTRIBUTION CHARGE:	$7.49 per Service Location (as defined below) *
VARIABLE DISTRIBUTION CHARGE:	$0.02412 per kWh

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ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2*.
* The service location charge includes an Energy Efficiency Program Surcharge ($0.08) per location.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

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SERVICE LOCATION.
A Service Location is the Point of Delivery on the Company's secondary circuit. That connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company.

DETERMINATION OF ENERGY BILLED.
The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules as set forth under Terms and Conditions, Paragraph 1 Service. The wattage, expressed to the nearest tenth of a watt, of a Service Location shall be composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls and other load components required for its operation. The aggregate of the kilowatt hours thus computed for all Active Service Locations shall constitute the energy billed for the month.

TERMS AND CONDITIONS.

1. Service. Lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer

2. Ownership of Utilization Facilities.

a. Service Locations Supplied from Aerial Circuits: customer shall provide, own and maintain the Utilization Facilities defined as the brackets, hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, conductors, molding and supporting insulators between the lamp receptacles and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location.
The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities. If the Company sells aerially supplied streetlighting facilities to a government agency in order to qualify for SL-E, such sale will include the supporting pole or post.

b. Service Locations Supplied from Underground Circuits: customer shall provide, own and maintain the Utilization Facilities defined as brackets or hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, and conductors and shall assume all costs of installing such Utilization Facilities. Customer shall also provide, own, and maintain the supporting pole or post foundation with 90 degree pipe bend, and conduits from the luminaires to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a Service Location designated by the Company on its secondary voltage circuit.
Except as provided in Paragraph 5 Supply Facilities, the Company shall own conduit from the distribution circuit to the 90 degree pipe bend, shall own conductors from its distribution system to the designated Service Location and shall provide sufficient length of conductors for splicing at the designated Service Location or in the post base where sidewalk level access is provided.

c. Service to Group of Utilization Facilities:

AERIAL SUPPLY
When the customer requests service to a group of Utilization Facilities supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the Utilization Facilities. The Company will provide a service, nominally 100 feet, to the customer's first supporting structure. The customer is responsible for installing supply conductors from the first supporting structure to all Utilization Facilities.

UNDERGROUND SUPPLY
When groups of Utilization Facilities are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each Utilization Facility from the designated Service Location. If the customer requests an underground supply to a group of Utilization Facilities and the designated Service Location is a secondary terminal pole, the customer will install, own, maintain all cable, including the cable on the pole.

3. Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

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RATE SL-E STREET LIGHTING CUSTOMER-OWNED FACILITIES (continued)

4. Power Factor. The Utilization Facilities provided by the customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

5. Supply Facilities. Lighting service shall be supplied from distribution facilities and equipment installed, owned and maintained by the Company. A customer contribution for new, additional or relocated lighting service may be required as described in Paragraph 11.

Where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control (such as bridges, overpasses, underpasses and limited access highways), the customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

6. Connection of Service Location. For new, additional or relocated Service Locations and for any modernization or maintenance work involving connections to the Company's distribution circuits, the customer will provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated delivery point on the Company's secondary voltage circuit. All work done by the customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

7. Service. Lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer.

8. Change in Size and Type of Service Locations. Written notice of any planned change in size or type of any components of Service Locations shall be furnished by the customer to the Company not less than 10 days prior to the effective date of such change. The customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings at any Service Location.

9. Service Maintenance. Upon receipt of report of a Service Location not receiving power, the Company will determine the cause of power failure and will restore service to the distribution circuit and control equipment, disconnecting, if necessary, any faulty Service Location from the circuit. Customer will make necessary repairs between the luminaires of the faulty utilization facilities and the point of connection to the Company's distribution circuit. In the event the fault is located in the Company owned facilities, the customer will bill the Company for this portion of the replaced facilities.

10. Authorization and Protection. The customer shall, to the extent of one's ability, furnish any requisite authority for the erection and maintenance of poles, wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the lighting system.

11. New, Additional or Relocated Lighting. The total costs to provide lighting service for new, additional or relocated lamps installed by the customer shall be subject to a revenue test. If the costs exceed the estimated revenue recovered through the Company's tariffed Variable Distribution Service Charges for four years, a customer contribution for all excess costs will be required.

12. Relocation of Service Locations. Where a pole is replaced by the Company at its own option, it shall be the customer's responsibility to have the Utilization Facilities transferred from the old to the new pole.

13. Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each Service Location shall be for at least one year.

PAYMENT TERMS.
Bills will be rendered monthly.

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RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.
Any governmental agency for outdoor lighting, provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, that complies with each of the following conditions:

(A) Installs a Smart Lighting Control Module approved by the Company that has capabilities including but not necessarily limited to:
a. Measurement of energy usage at the individual Utilization Facility level.
b. Customer control of the lamp's burning hours.
c. Data showing failure of the lamp to burn, such as customer notification, that customer can provide to Company upon request.
d. Ability of customer to dim the lights (LED only).
(B) Provides energy usage to the Company as described below under Data Requirements.
(C) Installs, owns, and maintains all Utilization Facilities, as defined in the Terms and Conditions of this Base Rate. (All facilities and their installation shall be approved by the Company.)

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers.

Customers may take service under the rate beginning on July 1, 2019. The below listed pricing will be revised, as needed, based on applicable surcharge adjustments prior to the SL-C effective service date of July 1, 2019.

MONTHLY RATE TABLE.
SERVICE LOCATION DISTRIBUTION CHARGE: $6.34 per Service Location (as defined below)*
VARIABLE DISTRIBUTION CHARGE: $0.04524 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 ($0.07) per location.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.
A Service Location is the Point of Delivery on the Company's secondary circuit that connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company

DATA REQUIREMENTS.
The customer must notify the Company of its intent to enroll or modify lights under this rate at least 30 days prior to the start of the regularly scheduled billing cycle during which the enrollment or modification will become effective.

The customer must provide the following data to the Company from its Company-approved Smart Lighting Control Module for each light added or modified:
8. Manufacturer-rated wattage
9. Annual burning hours, if different than the standard 4,100 burning hours as defined below under paragraph 1 Service of Terms and Conditions
10. Dimming percentage/factor

The Company also requires the customer to provide the Global Positioning System (GPS) coordinates for each light.

DETERMINATION OF ENERGY BILLED.
Upon acceptance of the required data, the Company shall modify the energy billed going forward for a period of up to twelve months or at another frequency as required by the Company. The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage, adjusted based on the provided dimming percentage/factor, and the provided burning hours during the calendar month.

The Company may, at any time and without prior notice, request that the customer provide updates to the above data or provide actual energy consumption data and burning hours for each light, by calendar month, for up to the past 12 months to verify the continued accuracy of Company billing.

For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, the Company shall modify the energy billed going forward by changing the burning hours used to the standard 4,100 burning hours as defined below under Paragraph 1 Service of Terms and Conditions.

The Company reserves the right to modify the customer's rate to SL-E in the continued absence of required data from the customer.

TERMS AND CONDITIONS.
1. Service. For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer. If the customer provides information from the Smart Lighting Control Module as described above to justify a different billing usage, the burning hours provided by the customer will be used instead of the standard 4,100 annual operating hours.

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RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES (continued)

2. Ownership of Utilization Facilities.
   a. Service Locations Supplied from Aerial Circuits: Customer shall provide, own and maintain the Utilization Facilities defined as the brackets, hangers, luminaires, lamps/LED array(s), ballasts/driver, transformers, Company-approved Smart Control Modules, conductors, molding and supporting insulators between the luminaires and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location. The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities. If the Company sells aerially supplied streetlighting facilities to a government agency in order to qualify for SL-C, such sale will include the supporting pole or post.
   b. Service Locations Supplied from Underground Circuits: Customer shall provide, own and maintain the Utilization Facilities defined as brackets or hangers, luminaires, lamps/LED array(s), ballasts/driver, transformers, individual controls, and conductors and shall assume all costs of installing such Utilization Facilities. Customer shall also provide, own, and maintain the supporting pole or post, foundation with 90 degree pipe bend and conduits from the luminaires to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a Service Location designated by the Company on its secondary voltage circuit. Except as provided in Supply Facilities, the Company shall own conduit from the distribution circuit to the 90 degree pipe bend, shall own conductors from its distribution system to the designated Service Location and shall provide sufficient length of conductors for splicing at the designated Service Location or in the post base where sidewalk level access is provided.
   c. Service to Group of Utilization Facilities:

      AERIAL SUPPLY

      When the customer requests service to a group of Utilization Facilities supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the Utilization Facilities. The Company will provide a service, nominally 100 feet, to the customer's first supporting structure. The customer is responsible for installing supply conductors from the first supporting structure to all Utilization Facilities.

      UNDERGROUND SUPPLY

      When groups of Utilization Facilities are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each Utilization Facility from the designated Service Location. If the customer requests an underground supply to a group of Utilization Facilities and the designated Service Location is a secondary terminal pole, the customer will install, own, maintain all cable, including the cable on the pole.

3. Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

4. Power Factor. The Utilization Facilities provided by the customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

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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.

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Where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control (such as bridges, overpasses, underpasses and limited access highways), the customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

6. Connection of Service Location. For new, additional or relocated Service Locations and for any modernization or maintenance work involving connections to the Company's distribution circuits, the customer will provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated Service Location on the Company's secondary voltage circuit. All work done by the customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

7. Change in Size and Type of Service Locations. Written notice of any planned change in size or type of any components of Service Locations, or any replacement of the Company-approved Smart Control Module, shall be furnished by the customer to the Company not less than 30 days prior to the effective date of such change. The customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings at any Service Location.

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8. Service Maintenance. Upon receipt of report of a Service Location not receiving power, the Company will determine the cause of power failure and will restore service to the distribution circuit and control equipment, disconnecting, if necessary, any faulty Service Location from the circuit. Customer will make necessary repairs between the luminaires of the faulty utilization facilities and the point of connection to the Company's distribution circuit. In the event the fault is located in the Company owned facilities, the customer will bill the Company for this portion of the replaced facilities.

9. Authorization and Protection. The customer shall, to the extent of one's ability, furnish any requisite authority for the erection and maintenance of poles, wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the lighting system.

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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: $4.08 PER LOCATION

VARIABLE DISTRIBUTION SERVICE CHARGE: $0.02144 per kWh (as defined below)*
*The Variable Distribution charge includes an Energy Efficiency Program Surcharge of ($0.00081) 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, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, NON-BYPASSABLE TRANSMISSION CHARGE, CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE 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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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 the burning hours and the date on which such new or changed operation took effect.

MONTHLY RATE TABLE.
SERVICE LOCATION CHARGE: $2.63 Per Location (as defined below)*
*The service location charge includes an Energy Efficiency Program Surcharge of ($0.02)

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

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT CLAUSE APPLY TO THIS RATE.

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PLAN OF MONTHLY BILLING.
Bills may be rendered in equal monthly installments, computed from the calculated annual use of energy, adjusted each month to give effect to any new or changed rate of annual use, by reason of changes in the City's installation, with charge or credit for fractional parts of the month during which a change occurred.

LIABILITY PROVISION.
The Company shall not be liable for damage, or for claims for damage, to persons or property, arising, accruing or resulting from, installation, location or use of lamps, wires, fixtures and appurtenances; or resulting from failure of any light, or lights, to burn for any cause whatsoever. The customer shall be responsible to determine the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

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APPLICABILITY INDEX OF RIDERS
Introductory Statement

Customers under different rates of this Tariff frequently desire services or present situations and conditions of supply which require special supply terms, charges or guarantees or which warrant modification of the amount or method of charge from the prices set forth in the Base Rate under which they are provided service. Modifications for such conditions are defined by rider provisions included as a part of this Tariff. Riders may be employed when applicable, with or without signed agreement between the customer and the Company as the case may require, notwithstanding anything to the contrary contained in the Base Rate to which the rider is applied.

Riders	Page No.	R	RH	RS	GS	PD	HT	POL	SL-S	SL-E	SL-C	EP	BLI	AL
Capacity Reservation Rider	75-79			X	X	X	X					X		
CAP Rider	80	X	X											
Casualty	81			X	X	X	X					X		
Construction	82				X[1]	X	X					X		
Economic Development	83-84				X	X	X							
Electric Vehicle DCFC Pilot Rider (EV-FC)	85-86				X	X	X							
Emergency Energy Conservation	87						X					X		
Investment Return Guarantee	88				X	X	X							
Night Service GS	89				X									
Night Service HT	90						X					X		
Night Service PD	91					X								
Receivership Rider	92				X	X	X	X	X	X	X	X		X
Temporary Service	93	X	X	X	X	X	X							

[1]Available only to Rate GS customers with demands greater than 500kW

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PILOT CAPACITY RESERVATION RIDER (CRR)

PURPOSE.
This Rider sets forth the eligibility, terms and conditions applicable to Customers who operate generation in parallel with the Company distribution system and for whom the Company needs to reserve electric capacity to serve their load when the customer's generation is offline.

This Rider also sets forth the eligibility, terms and conditions applicable to Customers who want to reserve capacity in excess of their present demand from the PECO distribution system for new business growth or expansion.

DEFINITIONS.
Demand and billing demand are defined in tariff sections "Definitions of Terms and Explanation of Abbreviations" and Section 15 of "Rules and Regulations".

(1) Ability to Shed Load – The capability of the customer to reduce or interrupt its total connected load as a means of offsetting some or all of the loss of its Parallel Generation, in the event that its Parallel Generation goes offline or is not operating to full capacity.

(2) Capacity Reservation – The contracted amount of firm electrical distribution capacity, expressed in kW, reserved by the Company solely to meet the capacity requirement for which a customer has contracted under the CRR.

(3) CRR Level –

a. For customers with Parallel Generation, the portion of their Capacity Reservation equal to the contracted percentage of the Generator Nameplate Capacity of their customer-owned Parallel Generation, determined pursuant to the provisions of the section of this Rider titled "Capacity Reservation vs. CRR Level Designation."

b. For customers seeking to reserve capacity for new business growth or expansion, the portion of their Capacity Reservation for which they have contracted under the CRR for that purpose.

(4) "Failure To Shed Load" Penalty – A charge assessed to a customer with a Capacity Reservation, CRR Level, or both that were set in whole or part based upon Ability to Shed Load when that customer's generator goes offline and the customer does not shed load as agreed upon.

(5) Generator Nameplate Capacity **–** The maximum rated output of a generator under specific conditions designated by the manufacturer.

(6) Operational Flexibility in Operation of Generation – The capability of the customer to flexibly operate multiple generating facilities as a means of offsetting some or all of the loss of its Parallel Generation, in the event that its Parallel Generation goes offline or is not operating to full capacity.

(7) Parasitic Load – The power consumed by the equipment supporting the operation of a customer's generation.

(8) Parallel Generation – Non-utility generating facility(s) approved for Parallel Operation.

(9) Parallel Operation – Occurs when a non-utility generating facility(s) interconnected with and operates while connected to PECO's distribution system, where the potential exists for electricity to flow from said generating facility(s) into PECO's electric distribution system.

(10) Uncovered Demand – The difference between the customer's CRR Level and the customer's Capacity Reservation

APPLICABILITY/AVAILABILITY.
Applicable to customers, with customer generating facilities that have generating capacity of 100 kW or greater and are first placed online, or are granted approval for Parallel Operation, after January 1, 2016. This includes but is not limited to Qualifying Facilities or Small Power Producers and cogenerators as defined in the Public Utility Regulatory Policies Act, whose electrical requirements are partially or wholly provided by facilities not owned by the Company and when such facilities operate in parallel with the Company's distribution system. All such customers will be supplied under the provisions of this rider, the customer's applicable Base Rate, and other applicable riders. Customers who wish to reserve available electrical capacity in excess of their present demand for new business growth or expansion may do so under this rider.

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PILOT CAPACITY RESERVATION RIDER (CRR) continued

NOTICE BEFORE COMMENCEMENT OF CRR SERVICE.

The customer shall not commence initial operation of any other source of supply in parallel with the Company's distribution lines until written permission is given by the Company for such parallel operation. Before a customer is placed on the CRR, the Company must provide written notice to the customer that includes the Capacity Reservation under the CRR and informs the customer that, upon receiving service under the CRR, capacity beyond this amount may not be available to serve the customer. The Company shall have the right to inspect the customer's installation prior to providing such written permission, and at any reasonable time thereafter in accordance with Tariff Rule 9.3.

CAPACITY RESERVATION VS. CRR LEVEL DESIGNATION.

The maximum firm capacity available to be reserved will be determined by the Company based upon its review of capacity available on its system at the time that a request for Capacity Reservation is made.

In all cases, if the requested electric capacity is not available the customer shall pay all cost to the Company of any construction necessary to meet the customer's Capacity Reservation requirement. To the extent that the requested capacity is needed for new business growth or expansion, the standard revenue test will apply when calculating the cost to be paid by the customer.
The Company must reserve capacity for a customer based upon an amount that the Company and customer agree accurately reflects the maximum demand that the Company must stand ready to serve to that customer.

For customers generating in parallel with the Company's distribution system:

For billing purposes, PECO will set the associated CRR Level as designated below:

For customers who have Generator Nameplate Capacity of greater than 100 kW but less than or equal to 5,000 kW, the CRR Level will be 60% of the Generator Nameplate Capacity.

For customers who have Generator Nameplate Capacity of greater than 5,000 kW but less than or equal to 10,000 kW, the CRR Level will be 50% of the Generator Nameplate Capacity.

Any customer, regardless of size of load or generation, may initiate negotiation as set forth below to designate the CRR at a level other than these levels.

Batteries and other electrical storage shall not be deemed to be generators for purpose of the CRR, and the nameplate capacity of storage or battery equipment shall not be included as, or treated as equivalent to, Parallel Generation for purposes of determining a customer's Capacity Reservation or CRR Level.

For customers who want to reserve capacity for new business growth or expansion, both the Capacity Reservation and the associated CRR Level will be determined by negotiation.

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PILOT CAPACITY RESERVATION RIDER (CRR) continued

NEGOTIATIONS FOR OPERATION OF CUSTOMER GENERATION.
If the CRR Level is set through negotiations for customers generating in parallel with the Company's distribution system, the following will apply:

The customer and PECO will meet to discuss customer operations. After such discussions, the customer may designate a CRR level other than as set forth above, based upon one or more of the following factors as defined above:

1. Parasitic Load: This will be subtracted from the customer's Generation Nameplate Capacity prior to determining the CRR Level.

2. Operational Flexibility in Operation of Generation: A customer with multiple generating units may commit to operate its facilities as a means of offsetting some or all of the loss of its Parallel Generation in a manner that reduces its Capacity Reservation requirement and consequently its CRR Level

3. Ability to Shed Load: A customer may commit to shed some portion of its total connected load to offset some or all of the loss of its Parallel Generation in a manner that reduces its Capacity Reservation requirement and consequently its CRR Level.

If PECO accepts the customer's designated Capacity Reservation and CRR Level then both amounts shall be set at the customer-designated level.

If PECO does not accept the customer's designated Capacity Reservation and or CRR Level then PECO may file a complaint with the PUC (to be referred to the Office of Mediation). Pending resolution of the complaint the Capacity Reservation and CRR Level shall be set at: as follows (subject to retrospective revision upon completion of the mediation/litigation):

- For customer designations based upon Parasitic Load, Operational Flexibility, or both, the Capacity Reservation and the CRR Level will be set at the customer-designated levels.

,

- For customer designations based in whole or part on Ability to Shed Load, the Capacity Reservation and CRR Level will be set at PECO-designated levels,

PROCEDURES TO CONFIRM MODE OF CUSTOMER GENERATION OPERATION
If a customer's CRR Level is set by negotiation based upon Parasitic Load or Operational Flexibility of Generation, or both, then:

- The customer shall inform PECO in writing if its generation operations differ materially from the mode of operations used to set the CRR Level;
- The customer shall verify to PECO once each calendar year that its generator operations in the prior year did not differ materially from the mode of operations used to set the CRR Level; and
- PECO shall have the right to conduct an audit of customer operations to determine whether generator operations differed materially from the mode of operations used to set the CRR Level.

NOTICE OF OPERATION CONTRARY TO A NEGOTIATED CRR LEVEL AND RESET PROVISION.
If, in its determination, PECO believes that a customer has operated its distributed generation units in a manner contrary to the mode of operations used to set the CRR Level, PECO may issue a written violation notice to the customer.

A customer shall not be deemed to have operated its distributed generation units in a manner contrary to the mode of operation used to set its CRR Level if both of the following are true:

- The customer was required to alter its mode of operations in response to a directive from PECO or because of conditions existing on PECO's distribution system.
- The customer's actual demand does not exceed its Capacity Reservation at any time.

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PILOT CAPACITY RESERVATION RIDER (CRR) continued

PECO will rescind a violation notice if, within 30 calendar days of receiving the violation notice, a customer furnishes evidence showing that it operated its distributed generation units consistent with the mode of operations used to set the CRR during the period in question. If PECO is not satisfied that the information provided by the customer demonstrates that operated its distributed generation units consistent with the mode operations used to set the CRR Level, PECO may file a complaint with the Commission and the Commission's determination shall prevail on whether the notice of violation will be deemed to be confirmed. If a customer does not furnish such evidence within 30 calendar days of receiving the violation notice, the violation notice is confirmed.

If a customer receives two confirmed violation notices within a 24-month period; the customer's going-forward CRR for the next 12 months shall be set at levels based upon the actual operations that led to the violation notice. Thereafter, the CRR may be reset to a lower levels only upon the customer demonstrating that it has made material changes to its mode of operations to allow it to operate in the then-described manner.

PENALTY AND RESET FOR FAILURE TO SHED LOAD.
For customers with a Capacity Reservation CRR Level or both that were set in whole or part based upon Ability to Shed Load, the following penalty and reset provisions shall apply:

- Penalty: If the customer's generator goes offline and the customer does not shed load as agreed upon the customer will be assessed a "Failure to Shed Load" Penalty" calculated by determining the amount of load that the customer agreed to shed, but did not shed, and applying a penalty charge equal to 125% of the full demand charge in the prevailing rate to that amount of load on the first such occurrence, and 150% of the full demand charge in the prevailing rate to that amount of load for the second and subsequent occurrences, for the month in which the load shedding did not occur.

- Reset: The customer's going-forward Capacity Reservation and CRR Level for the next 12 months shall be set at a level based upon the actual operations that occurred during the failure to shed load. Alternatively, the customer can opt to pay PECO for the actual cost of the required upgrades to PECO's distribution facilities to allow the customer to use delivery service at the higher operating level during outages in accordance with PECO's line extension policy (Tariff Rule 7.2). Thereafter, these amounts may be reset to a lower level only upon the customer demonstrating that it has made material changes to its mode of operations to allow it to operate in the then-described manner.

TEMPORARY DISCONNECTION OF CUSTOMER SERVICE.
PECO shall have the right to temporarily disconnect the customer on an emergency basis if, in PECO's opinion, the customer's failure to shed load as agreed creates a risk to PECO's distribution system or service to other customers.

BINDING LEGAL DUTY.
A CRR customer whose CRR Level is set at negotiated level based in whole or part upon the customer's representation that it has an Ability to Shed Load will be deemed to have a binding legal duty to shed such load.

RATE AND BILLING.
Subject to the Minimum Charge Provisions below, the demand charges under the customer's underlying applicable Base Rate of GS, HT, PD, and EP apply to the billing demand determined under the CRR.

Customers will be billed monthly their CRR Level plus actual electric demand and usage except as follow below:

For customers who reserve capacity due only to Parallel Generation, if such customer's actual registered demand is greater than the customer's Uncovered Demand for a given month, then, for that month only, the CRR Level used to calculate the customer's bill will be reduced by an amount equal to such difference, but in no event will the CRR Level be less than zero.

For customers who reserve capacity for business growth or expansion, if the customer's actual registered demand in a given month includes any portion of the CRR Level contracted for expansion for that month, then, for that month only, the CRR Level used to calculate the customer's bill will be reduced by an amount equal to said portion, but in no event will the CRR Level be less than zero.

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PILOT CAPACITY RESERVATION RIDER (CRR) continued

MINIMUM CHARGE.

Subject to the Rate And Billing provisions above the monthly minimum charge under the customer's underlying applicable Base Rate of GS, HT, PD, and EP will be calculated based on the minimum demand determined in accordance with the CRR. .
The monthly minimum demand charge for a customer reserving capacity due only to Parallel Generation will be the greater of:

1. The demand as registered by the customer's meter;
2. An amount equal to the customer's CRR Level, plus 40% of the customer's Uncovered Demand or
3. Any designated contract minimum.

The monthly minimum demand for a customer reserving capacity due only to new business growth or expansion will be an amount equal to the customer's CRR Level, plus 40% of the customer's Uncovered Demand
.
The monthly minimum customer charge will be determined by applying the minimum demand to the applicable demand charge for the Customer's underlying applicable Base Rate.

TERM OF CONTRACT.

The term of a CRR contract shall be three years for all non-negotiated CRR applications. For negotiated CRR Levels, the contract term shall be negotiated. There is no right to automatic renewal of a CRR; upon the expiration of the contract term, the Company will review available capacity on its system and, if such capacity is available, the parties will enter into a new CRR contract using the procedures set forth above.

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CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER

AVAILABILITY.
To payment-troubled customers who are currently served under or otherwise qualify for Rate R or RH (excluding multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for the rates contained in this rider and must demonstrate annual household gross income at or below 150% of the Federal Poverty guidelines. Customers will be subject to a $20 monthly bill minimum ($10 for non-heating customers) and will not be eligible to obtain Competitive Electric Supply or participate in budget billing. Commencing September 1, 2021 these customers will not be eligible to select the Time-Of-Use default service option.

Based on the applicable level of income and number of household members, CAP customers will receive a monthly fixed bill or Percentage of Income Payment Plan ("PIPP") based upon that individual household's need. The details of the PIPP calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No. M-2018-3005795.

CERTIFICATION/VERIFICATION.
Prior to enrollment in the CAP Rider, customers must verify, to PECO's satisfaction, that their household income level meets the "Availability" standards set forth in this Rider. Customers being considered for the CAP Rider will be required to:

- Provide information sufficient to demonstrate to PECO their household income level.
- Waive certain privacy rights to enable PECO to effectively conduct the above certification process.
- Participate in various energy education and conservation programs offered by PECO if identified as high-usage.

PECO may, at its sole discretion, supplement this verification process by using data from Commonwealth or federal government programs which demonstrate the income eligibility of its customers. Such data may come from a customer's participation in, or receipt of benefits from, the Low Income Home Energy Assistance Program, Temporary Assistance for Needy Families, Food Stamps, Supplemental Security Income, and Medicaid. Information available from the Pennsylvania Department of Revenue may also be used where appropriate to expedite the process.

MINIMUM CHARGE.
The minimum charge per month will be $10 for Residential customers or $20 for Residential Heating customers.

ARREARAGE.
Customers who qualify and are enrolled in CAP for the first time will have their pre-program arrearage ("PPA") forgiven if the customer pays his / her new, discounted CAP bill on time and in full each month. With every full and on-time monthly payment, one-twelfth of the PPA will be forgiven. PECO allows for customers who may have missed PPA "forgiveness" due to late or missed payments to "catch-up" on missed PPA forgiveness; whenever a customer brings their bill current, PECO will forgive any missed forgiveness the customer did not receive during that time. If the customer develops any in-program arrearage while on the CAP Rate–that is, if the customer does not pay the entire outstanding balance – then preprogram arrearage forgiveness will not resume until the first month in which the full outstanding balance is paid.

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CASUALTY RIDER

AVAILABILITY/APPLICABILITY.
To service provided during a period when a customer is prevented for a length of time in excess of 48 hours from using all or a substantial part of the amount contracted for by reason of strike, riot, fire, storm, flood, drought, interference by civil or military authorities, or any other cause beyond the customer's control ("Period of Interruption").

NOTICE REQUIRED.
Written request shall be made to the Company for the application of this rider with advice as to the extent of the interruption, its date, cause and probable duration. Written requests must be submitted to the Company within 30 calendar days after the end of the Period of interruption.

RATE IMPACT.
During Periods of Interruption, PECO Energy will not apply guarantees of revenue (power factor adjustment, minimum billing demand, and contract minimum) as contained in the customer's Contract, but will apply the actual registered demand. If the customer receives Default Service, the terms of this rider shall not apply to the Energy Supply Charge.

BILLS PRORATED.
Bills supplied shall be prorated, based upon the actual level of operation during the Period of Interruption.

RETURN TO NORMAL USE.
The customer shall use reasonable diligence in resuming the use of service as provided in the Contract.

TERM OF CONTRACT.
The initial contract term shall be extended for a period equal to the Period of Interruption so that the Company shall secure a working term at full connected load equal to the term of the Contract.

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CONSTRUCTION RIDER

AVAILABILITY/APPLICABILITY.
To service provided during or immediately following a major construction or expansion period or during a receding load period, after the expiration of the initial contract term, while a business is in process of dissolution. A major construction or expansion period is defined as a construction or expansion project undertaken by the customer which upon completion will require an upward modification of the customer's contract limits.

RATE IMPACT.
During the expanding load period preceding the operation within the load limits provided in the contract or the receding load period subsequent to the fulfillment of the initial contract term, PECO Energy will not apply the following guarantees of revenue: power factor adjustment, minimum billing demand, and contract minimum. If the customer receives Default Service, the terms of this rider shall not apply to the Energy Supply Charge.

RIDER TERM.
The total term of application of this rider during the preliminary or construction period shall be 6 months subject to the option of the Company to grant not more than three successive renewals of the rider term on major construction projects. Its application during a receding load period subsequent to the completion of an initial contract term shall be for not more than one year.

TERM OF CONTRACT.
The initial contract term for service to expanding locations to which this rider is applied shall be extended for a period corresponding to the total number of months this rider is applied to the customer's bill during construction or expansion of the customer's facility.

OTHER RIDERS.
This rider, when applied to service to temporary installations to which the Temporary Service Rider is also applied, shall not operate as a waiver of the requirement that monthly minimum charges be paid for a period of not less than 6 months.

For customers taking service under PECO's Capacity Reservation Rider (CRR), the terms of the Construction Rider shall only apply to actual demand for load behind the meter that is not covered by the CRR Level, as defined within the terms and conditions of the CRR.

ECONOMIC DEVELOPMENT RIDER

AVAILABILITY/APPLICABILITY. This rider is available to customers taking distribution service under Rate HT, PD, or GS. For new services, the customer must have a projected load of at least 350 kW and must apply for the rider prior to the service being energized. For existing services, the customer must have a peak load of at least 350 kW and apply for the rider before the load growth occurs. The Company will not begin to apply the rider until at least 30 days after the customer provides to the Company written notice of its desire to be placed on the rider. Customers can qualify for this rider through provisions of either I-A, I-B, or II below. This Rider shall be available to customers regardless of whether the energy is purchased under default service rates or through an EGS.

I. **EMPLOYMENT & LOAD GROWTH**: designed to encourage growth in all sectors of the industrial and commercial group, customers can qualify by meeting the appropriate requirements below.

A. **QUALIFICATIONS**.

1. Manufacturing Customers
   a. The New Manufacturing Customer or existing manufacturing customer files with the Company, before the effective date of the rider for the Service Location, a Manufacturing Sales Tax Exemption Certificate, as defined below, for the Service Location. This condition is waived for Stevedoring Operations located within a Port Enterprise Development Area as defined in Title 12, Chapter 121 of the Pennsylvania Code.
   b. The existing manufacturing customer files with the Company copies of the Base Period Employment Reports as defined below, for the Service Location.
   c. For existing locations has already demonstrated a minimum 10 new jobs and a sustained increase in usage (minimum of 100 kW for at least 3 months) over the Base Period, as defined below. The Company reserves the right to request documentation to demonstrate that employment levels have been maintained over the course of eligibility for this rider.
2. Brownfield Redevelopment
   a. A new or existing customer who develops a site designated as a Brownfield Site (defined below) and demonstrates a minimum of 100 kW of new or incremental load.
3. Large Load Growth
   a. A new or existing customer who adds an additional 100MW or more of new load and adds a minimum of 10 new jobs.
4. Hydrogen Production
   a. A new or existing customer who develops on-site hydrogen production.

B. **RATE REDUCTION.** The rate reduction will be applicable to the customer's base bill for the Qualifying Service Location before the application of the State Tax Adjustment, Federal Tax Adjustment Credit and Nuclear Decommissioning Cost Adjustment.

Any customer will not be eligible for the rate reduction in any month in which the customer has an unpaid balance which includes late payment charges.

1. Monthly Eligibility – The Company reserves the right to require updated documentation in order for the customer to remain eligible for the rider.
2. A credit equivalent to 15% of the customer's Variable Distribution Service Charge ("VDC"). For New Manufacturing locations or Brownfield Redevelopment the credit will apply to all kW of the VDC. For all existing customers the credit will apply to all incremental kW of the VDC. For hydrogen producers, the credit will apply to the portion of the customer's billed kW of the VDC associated with their hydrogen production equipment nameplate.

I. **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)
(Effective July 1, 2019 through December 31, 2025)

AVAILABILITY/APPLICABILITY.
Applicable to a service that includes at least one permanently connected and publicly available (workplace fleet and public transit) Public Direct Current Fast Charger ("DCFC") served under Rate GS, PD, or HT installed on or after July 1st, 2019. The Company may apply this rider to either a stand-alone metered DCFC or to a DCFC served as part of an existing service.

The pilot began on July 1, 2019 and expires on December 31, 2025.
The pilot will be modified and extended beginning on January 1, 2026 through December 31, 2030 (Docket No. R-2024-3046932).

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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 and in accordance with the Commission's Policy Statement at Docket No. M-2017-2604382.

DEFINITIONS.
Electric Vehicle (EV) – Any vehicle licensed to operate on public roadways that is propelled in whole or in part by electrical energy stored on-board for the purpose of propulsion. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles and battery electric vehicles.

Electric Vehicle Supply Equipment (EVSE) – A device which permits the transfer of electric energy (by conductive or inductive means) to a battery or other energy storage device in an EV.

Public Direct Current Fast Charger (DCFC) – A high powered, publicly available (including workplace fleet and public transit) EVSE solely dedicated to recharging an EV's battery via the use of direct current, inductive charging, or other EV charging technology with equivalent capabilities. To be considered publicly available, the DCFC must be located along a public roadway corridor, at a public charging location, at a multi-dwelling unit (MDU) residential building at a public transit charging location, or at a workplace for fleet or customer charging.

INSTALLATION AND ENROLLMENT.
The Company shall provide service based on the DCFC's nameplate capacity rating when the Company has available distribution facilities with sufficient capacity, and if the provision of service will not in any way interfere with service to other customers.

Electric Vehicle charging stations shall be constructed in accordance with the Company's service installation policies contained in its Electric Service Requirements Manual ("Blue Book"), a copy of which may be found at www.peco.com. The customer, who may be either the owner or the host of a third-party owned DCFC, shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company.

The station must be designed to protect for back flow of electricity to the Company's electrical distribution circuit. The owner of the DCFC is responsible for maintaining a safe operating environment for the device(s). The Company shall not be liable for any damage or injury, including any consequential damage, resulting from the operation of the DCFC.

The Customer may be responsible to submit an application and documentation of the completed DCFC installation to the Company in order to become eligible for the rider.

TRANSFER OF OWNERSHIP
If, during the term of contract, the ownership of the service location changes, the Company may continue to apply the rider to the new owner's bills for the Service Location. If the Company continues to apply the rider in such circumstances, the Company shall apply the rider to the new owner's bills for the Service Location as if the new owner had been on the rider for the Service Location for the same period of time as was the previous owner.

MISCELLANEOUS GENERAL PROVISIONS.
If the owner requests that service to the DCFC be permanently disconnected, the Company reserves the right to charge that owner for the removal of any required facilities and equipment previously required to furnish service to the DCFC. Such payment by the owner shall not confer upon, nor entitle the customer to any title to, or right of property in, said facilities and equipment.

Pilot participants will be required to provide data for all DCFCs connected to the PECO system and not separately metered in order to allow PECO to investigate the development of future DCFC rates. This data will include, for each DCFC: the number installed, the number of charging ports, the nameplate capacity (in kW), hourly and monthly usage (kWh), and the hourly and monthly demand (kW).

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ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC)
(Effective January 1, 2026 through December 31, 2030)

AVAILABILITY/APPLICABILITY.
Applicable to a service that is dedicated to Electric Vehicle Supply Equipment (EVSE) and includes at least one permanently connected Direct Current Fast Charger ("DCFC") served under Rate GS, PD, or HT installed on or after July 1st, 2019. The Company may apply this rider to either a stand-alone metered DCFC or to a DCFC served as part of an existing service. The Company may, at its sole discretion, apply this rider to a service that has both DCFC and other forms of EV charging so long as the combined maximum nameplate capacity rating for all DCFCs connected to the service is equal to at least 80% of the combined maximum nameplate capacity rating for all EVSE connected to the service. The Company may, at its sole discretion, apply this rider to a service that has other loads ancillary to EV charging such as signage, lighting, and communication equipment so long as the maximum combined demand of such loads does not exceed one percent of the combined maximum nameplate capacity rating for all EVSE connected to the service.

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The pilot extension begins on January 1, 2026 and expires on December 31, 2030.

The owner of the DCFC shall be responsible for all applicable Tariff rates, fees and charges. The Electric Vehicle owner using the DCFC shall be responsible for all fees imposed by the owner of the station for charging the electric vehicle.

The DCFC is exempt from resale provisions as outlined in Tariff Rule 13.1 and in accordance with the Commission's Policy Statement at Docket No. M-2017-2604382.

DEFINITIONS.
Electric Vehicle (EV) – Any vehicle licensed to operate on public roadways that is propelled in whole or in part by electrical energy stored on-board for the purpose of propulsion. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles and battery electric vehicles.

Electric Vehicle Supply Equipment (EVSE) – A device which permits the transfer of electric energy (by conductive or inductive means) to a battery or other energy storage device in an EV.

Direct Current Fast Charger (DCFC) – A high powered EVSE solely dedicated to recharging an EV's battery via the use of direct current, inductive charging, or other EV charging technology with equivalent capabilities. To be considered high-powered, the DCFC must have a nameplate charging capacity of at least 50 kilowatts per charging port.

INSTALLATION AND ENROLLMENT.
The Company shall provide service based on the DCFC's nameplate capacity rating when the Company has available distribution facilities with sufficient capacity, and if the provision of service will not in any way interfere with service to other customers.

Electric Vehicle charging stations shall be constructed in accordance with the Company's service installation policies contained in its Electric Service Requirements Manual ("Blue Book"), a copy of which may be found at www.peco.com. The customer, who may be either the owner or the host of a third-party owned DCFC, shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company.

The station must be designed to protect for back flow of electricity to the Company's electrical distribution circuit. The owner of the DCFC is responsible for maintaining a safe operating environment for the device(s). The Company shall not be liable for any damage or injury, including any consequential damage, resulting from the operation of the DCFC.

The Customer may be responsible to submit an application and documentation of the completed DCFC installation to the Company in order to become eligible for the rider.

TRANSFER OF OWNERSHIP
If, during the term of contract, the ownership of the service location changes, the Company may continue to apply the rider to the new owner's bills for the Service Location. If the Company continues to apply the rider in such circumstances, the Company shall apply the rider to the new owner's bills for the Service Location as if the new owner had been on the rider for the Service Location for the same period of time as was the previous owner.

MISCELLANEOUS GENERAL PROVISIONS.
If the owner requests that service to the DCFC be permanently disconnected, the Company reserves the right to charge that owner for the removal of any required facilities and equipment previously required to furnish service to the DCFC. Such payment by the owner shall not confer upon, nor entitle the customer to any title to, or right of property in, said facilities and equipment.

Pilot participants will be required to provide data for all DCFCs connected to the PECO system in order to allow PECO to investigate the development of future DCFC rates. This data will include, for each DCFC: the number installed, the number of charging ports, and the nameplate capacity (in kW).

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ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) (continued)
(Effective July 1, 2019 through December 31, 2025)

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RATE IMPACT.
All terms and guarantees of the applicable Base Rate are applicable. The Company shall calculate and apply a fixed demand (kW) credit, initially equal to 50% of the combined maximum nameplate capacity rating for all DCFCs connected to the service, to the customer's billed distribution demand. At no time will the billing demand be less than the minimum demand applicable under the provisions of the applicable Base Rate. The Company reserves the right to reduce the demand credit based on a comparison of the customer's peak demands before and after installation of the DCFC.

If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

OTHER RIDERS.
This rider, when applied to temporary service installations to which the Temporary Service Rider is also applied, shall not operate as a waiver of the requirement that monthly minimum charges be paid for a period of not less than 6 months.

When this rider is applied to a service to which the Night Service GS Rider, Night Service HT Rider, or Night Service PD Rider is also applied, the variable demand credit shall apply to the Off-Peak Billing demand.

This rider will not be applied in conjunction with the Economic Development Rider.

TERM OF CONTRACT.
The Company shall provide this credit for no more than 36 months from the date of enrollment or until the conclusion date of the pilot, whichever comes first. There is no right to automatic renewal. Extended participation may be possible and could be predicated on future regulatory directives as yet to be determined.

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ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) (continued)
(Effective January 1, 2026 through December 31, 2030)

RATE IMPACT.
All terms and guarantees of the applicable Base Rate are applicable. The Company shall calculate and apply a variable demand (kW) credit, equal to 20% of the measured demand to the customer's billed distribution demand. For services where the minimum demand would be calculated under the applicable base as 40% of the maximum contract demand, the Company shall instead calculate minimum demand as 30% of the maximum contract demand. Otherwise, the minimum demand shall be 15 kW.

If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

OTHER RIDERS.
This rider, when applied to temporary service installations to which the Temporary Service Rider is also applied, shall not operate as a waiver of the requirement that monthly minimum charges be paid for a period of not less than 6 months.

When this rider is applied to a service to which the Night Service GS Rider, Night Service HT Rider, or Night Service PD Rider is also applied, the variable demand credit shall apply to the Off-Peak Billing demand.

This rider will not be applied in conjunction with the Economic Development Rider.

TERM OF CONTRACT.
The Company shall provide this credit for no more than 36 months from the date of enrollment or until the conclusion date of the pilot, whichever comes first. There is no right to automatic renewal.

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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: $24.56

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Charge per kW of Off-Peak billing demand per month: $4.17

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STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), 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: $11.45
Charge per kW of Off-Peak billing demand:
$3.53 per month for Rate HT.
$3.24 per month for Rate EP.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) APPLIES TO THIS RIDER.

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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.

NIGHT SERVICE PD RIDER

AVAILABILITY/APPLICABILITY.
To distribution service provided during Off-Peak Hours for demands in excess of those supplied during On-Peak Hours. The demand specified for Off-Peak Hours shall be limited to an amount determined by the Company which shall be dependent upon the capacity of the generation, trademark and distribution facilities available for such supply.

DEFINITION OF PEAK HOURS.
On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the On-Peak Hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as On-Peak Hours.

RATE IMPACT.
Rate PD, including all terms and guarantees, is applicable during On-Peak Hours. If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

MONTHLY RATE TABLE.

Night Service billing and metering charge: $11.45
Charge per kW of Off-Peak billing demand per month: $4.53

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) 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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TEMPORARY SERVICE RIDER

APPLICABILITY.
To the provision of service, including builders construction service, when the Company must install temporary facilities that will be used for a limited period or for a service that is of doubtful permanency.

AVAILABILITY.
Temporary service will be provided only when the Company has available distribution facilities with sufficient capacity, and if the provision of service will not in any way interfere with service to other customers.

INVESTMENT IN DISTRIBUTION FACILITIES.
The cost of the extension and removal of facilities required to furnish the temporary service under the applicable rate shall be paid by the customer, but such payment shall not confer upon, nor entitle the customer to any title to, or right of property in, said facilities and equipment.

MINIMUM TERM.
Application of this rider to Rates R, R-H and GS shall not, for billing purposes, be considered to be for a period of less than one month.

Application of this rider to Rates PD and HT shall require payment of the minimum provisions of the contract for each month of the temporary service period, but in no case shall such period be considered, with respect to the guarantee of the monthly minimum charges, as of less duration than 6 months.

RATE IMPACT.
Billing shall be under the provisions of the applicable base rate and riders.

TERM OF CONTRACT.
Short term arrangements as agreed upon.

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Effective January 1, 2022

PECO Exhibit JAB-3:

Comparison of Residential Customer Charges for Pennsylvania Electric Distribution Utilities

Comparison of Residential Customer Charges for Pennsylvania Electric Distribution Utilities

Company	**Current Base Residential Customer Charge**
Citizens Electric	$ 13.10
Duquesne	$ 12.50
MetEd	$ 11.25
Pennelec	$ 11.25
Penn Power	$ 11.00
PPL	$ 14.09
UGI	$ 10.75
West Penn	$ 7.44
PECO Current	**$ 10.50**
PECO Proposed	**$ 14.25**

PECO Exhibit JAB-4:

Proof of Revenues at Present and Proposed Rates

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Residential (R)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	1,000,000	$ 10.00	$ 120,000,000	$ 12.00	$ 144,000,000
3	Net Load Meter	50,000	$ 0.00	$ 600,000	$ 0.00	$ 600,000
4						
5	**Total Customer Charge Revenue**			$ 120,600,000		$ 144,600,000
6						
7	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	Base Rate	11,000,000,000	$ 0.00000	$ 0	$ 0.00000	$ 0
9						
10	CAP Credits - Distribution			$ (1,000,000)		$ (1,000,000)
11	CAP Credits - Non-Distribution			$ (500,000)		$ (500,000)
12	CAP Shortfall			$ 1,000,000		$ -
13						
14	Distribution Uncollectible Net Charge (DNC)			$ 1,000,000		$ -
15						
16	**Total Variable Distribution Revenue**			$ 500,000		$ 500,000
17						
18	Regulatory Initiative			$ 1,000,000		$ 1,000,000
19	Load Reduction			$ (1,000,000)		$ (1,000,000)
20	Normalization			$ 1,000,000		$ 1,000,000
21						
22	**Adjusted Total Distribution Revenue**			$ 121,000,000		$ 145,000,000

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Residential Heating (RH)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	1,000,000	$ 10.00	$ 120,000,000	$ 15.00	$ 180,000,000
3						
4	**Total Customer Charge Revenue**			$ 120,000,000		$ 180,000,000
5						
6	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Base Rate June-September	4,000,000,000	$ 0.00500	$ 20,000,000	$ 0.00750	$ 30,000,000
8	Base Rate October-May	6,000,000,000	$ 0.00500	$ 30,000,000	$ 0.00750	$ 45,000,000
9						
10	CAP Credits - Distribution			$ (2,000,000)		$ (2,000,000)
11	CAP Credits - Non-Distribution			$ (1,000,000)		$ (1,000,000)
12	CAP Shortfall			$ 1,000,000		$ -
13						
14	Distribution Uncollectible Procurement Charge (DSIC)			$ 500,000		$ -
15						
16	**Total Variable Distribution Charge Revenue**			$ 48,500,000		$ 72,000,000
17						
18	Regulatory Initiative			$ 1,000,000		$ 1,000,000
19	Load Reduction			$ (500,000)		$ (500,000)
20	Normalization			$ 1,500,000		$ 1,500,000
21						
22	**Adjusted Total Distribution Revenue**			$ 169,000,000		$ 253,000,000

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - General Service (GS)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	□i□g□e-Pha□e - □o De□a□d	373,53 1	$ 18.99	$ 7□093 □□61	$ 24.47	$ 9, ˙40,313
3	□i□g□e-Pha□e - □ ith De□a□d	1□099,42 0	$ 24.2 1	$ 26,6 16,967	$ 31.20	$ 34,3 01,916
4	Po□□-Pha□e - □ ith De□a□d	405,8 13	$ 57.94	$ 23,5 12,8 19	$ 74.66	$ 30,298 □016
5	G□ □ight □er□i□e Rider	34,963	$ 19□06	$ 666,386	$ 24.56	$ 858,68 0
6						
7	**Total Customer Charge Revenue**			$ 57,889,533		$ 74,598,925
8						
9	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
10	Ba□e Rate	7,546,79 1,99 0	$ □0□0006)	$ (4,528 □075)	$ □0□0006)	$ (4 □□28 □075 □
11						
12	**Total kWh-Based Variable Distribution Revenue**			$ (4,528 □075)		$ (4 □□28 □075 □
13						
14	**kW-Based Variable Distribution Charges**	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
15	Ba□e Rate	24, □20,966	$ 8. ˙2	$ 201,546,247	$ 11.50	$ 285,556,876
16	G□ □ight □er□i□e Rider	119,862	$ 2.94	$ 352,394	$ 4. ˙7	$ 499,283
17						
18	**Total kW-Based Variable Distribution Revenue**			$ 201,898,64 1		$ 286 □056, ˙59
19						
20	Di□trib□tio□ Sys :em I□ □ro□e□e□t Charge □D□IC)			$ 10,879 □090		$ -
21						
22	**Total Variable Distribution Charge Revenue**			$ 208,249,656		$ 281,528 □084
23						
24	Reg□ator□ I□itiati□e□			$ 48,855		$ 48,855
25	□oad Red□□tio□			$ (89 1,55 0)		$ (□193 □004 □
26	□□□□a i□atio□			$ 722, ˙99		$ 966,39 1
27						
28	**Adjusted Total Distribution Revenue**			$ 266 □018 □□93		$ 35 □□□49 □□51

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Primary Distribution (PD)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	0	$	$	$	$
3	PD Light Service Rider	1	$	1	$	1
4						
5	**Total Customer Charge Revenue**			$		$
6						
7	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	Base Rate	0	$	$	$	$
9						
10	**Total kWh-Based Variable Distribution Revenue**			$		$
11						
12	**kW-Based Variable Distribution Charges**	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
13	Base Rate	0	$	$	$	$
14	PD Light Service Rider	1	$	$	$	1
15						
16	**Total kW-Based Variable Distribution Revenue**			$		$
17						
18	Distribution Uncollectible Provision Charge (DUPIC)			$		$ -
19						
20	**Total Variable Distribution Charge Revenue**			$		$
21						
22	Regulatory Initiative			$		$
23	Load Reduction			$		$
24	Normalization			$		$
25						
26	**Adjusted Total Distribution Revenue**			$		$

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - High Tension (HT)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
	Ba e Rate	1	11	1	1 1 0	
	HT ight er i e Rider	1 1	11	1 0	11	1
	Total Customer Charge Revenue			11 1		1 0
	kWh-Based Variable Distribution Charges	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
	Ba e Rate	1 1	0 000	0 1	0 000	0 1
10	**Total kWh-Based Variable Distribution Revenue**			0 1		0 1
11						
1	**kW-Based Variable Distribution Charges**	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	Ba e Rate	1	1 0	1		1
1	HT ight er i e Rider	1		0		1 11
1	High o tage Di o t					
1		0 1	0 1	1 0	0	0
1		1 0	1	1	1	1
1		1 0	1		1	
1						
0	**Total kW-Based Variable Distribution Revenue**			1 0		11 1
1						
	Di trib tio te I ro e e t Charge DIC					-
	Total Variable Distribution Charge Revenue			1 0 1		0 10
	Reg ator I itiati e			0		0
	oad Red tio			0		0
	a i atio			1		1 1 1
0	**Adjusted Total Distribution Revenue**			1 0		1

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Electric Propulsion (EP)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
	Ba e Rate		1	00	1	00
	EP ight er i e Rider	0	11		11	
	Total Customer Charge Revenue			01		01 0
	kWh-Based Variable Distribution Charges	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
	Ba e Rate	0 000	0 000	0	0 000	0
	Total kWh-Based Variable Distribution Revenue			0		0
	kW-Based Variable Distribution Charges	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
	Ba e Rate	1 0 0		1		
	EP ight er i e Rider	1	1	10		1
	High o tage Di o t					
	for fir t 10 000 of ea red de a d e	1	0 1	1	0	
	for fir t 100 000 of ea red de a d	-	1	-	1	-
	for fir t 100 000 of ea red de a d	0	1	01 10	1	
	Total kW-Based Variable Distribution Revenue			1 1 0		1
	Di trib tio te I ro e e t Charge DIC			0 01		-
	Total Variable Distribution Charge Revenue					
	Reg ator I itiati e			-		-
	oad Red tio			-		-
	a i atio			-		-
	Adjusted Total Distribution Revenue			0		1

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Proof of Revenue at Present and Proposed Rates - Lighting

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer-Owned Lighting**					
	Service Location Charges	**Locations**	**Rate**	**Revenue**	**Rate**	**Revenue**
	-E	1		1		1
	-C	1		1		11
	TC	10		1		11
		1				1
	Total Service Location Charge Revenue			1		1
10	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
11	-E	10	0	1	0	11
1	-C	1	0	1	0	
1	TC	0	0	0	0	0
1	**Total kWh-Based Variable Distribution Revenue**			1		11
1	**Company-Owned Lighting**					
1	**Component-Based Distribution Charges**			**Revenue**		**Revenue**
1	-			0		0
0	PO			1		0
1	**Total Component-Based Distribution Revenue**			1		
	Di trib tio te I ro e e t Charge DIC			0		-
	Total Distribution Revenue			0		
	Reg ator I itiati e			-		-
	oad Red tio			-		-
	a i atio			-		-
0	**Adjusted Total Distribution Revenue**			0		

PECO Exhibit JAB-5:

Modified Base Rate Recovery of CAP Revenues in USFC

C-Factor Period	Estimated CAP Credits ($)	Estimated R/RH Sales (a) (kWh)	Estimated Shortfall Recovered in Base Rates (b)	Shortfall o/(u) Base Recovery	Shortfall o/(u) Base Recovery (c)
			(3) = (2) * $0.0068 thru 12/31/2024		(5) = (4) * 0.73 thru 12/31/2024
	(1)	(2)	(2) * $0.0102 as of 1/1/2025	(4) = (1) - (3)	(4) * 0.895 as of 1/1/2025
Jan-25					
Feb-25					
Mar-25					
Apr-25					
May-25					
Jun-25					
Jul-25					
Aug-25					
Sep-25					
Oct-25					
Nov-25					
Dec-25					
	$ -	-	$ -	$ -	$ -

Please reference Column (3), Column (5), and Notes (b-c) for PECO's proposed change.

(a) Non-CAP kWh.
(b) Current factor is per settlement approved at Docket No. R-2010-2161575.
PECO is proposing to update these factors effective January 1, 2025.

Projected FPFTY 2025 CAP Bill Credits:	$	145,200,000
Projected Res Non-CAP Sales for FPFTY 2025 (kWh):		14,258,563,289
Resulting Base Rate Recovery per kWh:	$	0.0102

(c) Current factor is per settlement approved at Docket No. P-2008-2062739.
PECO is proposing to update this factor effective January 1, 2025 from 73% to 89.5%

E-Factor Period	Total CAP Credits (Shortfall)	Billed R/RH Sales (a) (kWh)	CAP Revenues Recovered in Base Rates (b)	Base Recovery o/(u) Actual	Base Recovery o/(u) Actual (c)	C-Factor Revenue	L-Factor Revenue (d)	L-Expenditures	L - Factor o/(u) Recovery	InPA Revenue (e)	InPA Balance	InPA o/(u) Recovery	Total C, L & F Factor o/(u) Recovery
			(3) = (2) * $0.0068 thru 12/31/2024		(5) = (4) * 0.73 thru 12/31/2024								
	(1)	(2)	(2) * $0.0102 as of 1/1/2025	(4) = (3) - (1)	(4) * 0.895 as of 1/1/2025	(6) = (2) * ($0.00054)	(7) = (2) * $0.00024	(8)	(9) = (7) - (8)	(10) = (2) * ($0.00016)	(11)	(12) = (10) - (11)	(13) = (5) + (6) + (9) + (12)
Jan-24													
Feb-24													
Mar-24													
Apr-24													
May-24													
Jun-24													
Jul-24													
Aug-24													
Sep-24													
Oct-24 (a)													
Nov-24 (a)													
Dec-24 (a)													
	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Please reference Column (3), Column (5), and Notes (b-c) for PECO's proposed change.

(a) Residential Non-CAP Sales.
(b) Current factor is per settlement approved at Docket No. R-2010-2161575.
PECO is proposing to update these factors effective January 1, 2025.

Projected FPFTY 2025 CAP Bill Credits:	$	145,200,000
Projected Res Non-CAP Sales for FPFTY 2025 (kWh):		14,258,563,289
Resulting Base Rate Recovery per kWh:	$	0.0102

(c) Current factor is per settlement approved at Docket No. P-2008-2062739.
PECO is proposing to update this factor effective January 1, 2025 from 73% to 89.5%
(d) LIURP Health/Safety and De-facto heating. Per settlements at Docket No. R-2018-3000164 & R-2021-3024601.
(e) InPA Remaining Balance.

PECO ENERGY COMPANY
STATEMENT NO. 7-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

REBUTTAL TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECT: RESPONDING TO OPPOSING PARTIES' TESTIMONY REGARDING PECO ENERGY COMPANY'S REVENUE ALLOCATION; SCALE BACK OF RATES; AND CUSTOMER CHARGES

DATED: JULY 16, 2024

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III. SCALE BACK 8

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V. CONCLUSION 12

REBUTTAL TESTIMONY
OF
JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Joseph A. Bisti. I am employed by PECO Energy Company ("PECO" or the "Company") as a Manager of Rate Analysts. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct testimony marked as PECO Statement No. 7. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to: (1) Office of Consumer Advocate ("OCA") witness Clarence Johnson, Bureau of Investigation and Enforcement ("I&E") witness Esyan Sakaya, Office of Small Business Advocate ("OSBA") witness Kevin C. Higgins, Philadelphia Area Industrial Energy Users Group ("PAIEUG") witness Billie S. LaConte, Southeastern Pennsylvania Transportation Authority ("SEPTA") witness James L. Crist, and Walmart Inc. ("Walmart") witness Lisa V. Perry regarding the proposed revenue allocation I prepared on behalf of PECO and which was attached to my direct testimony as Exhibit JAB-1; and (2) OCA witness Johnson, OCA witness Roger D. Colton, and Tenant Union Representative Network ("TURN") and Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-

PA") (together "TURN/CAUSE-PA") witness Elizabeth R. Marx regarding PECO's proposed customer charges.

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

A. Yes, I have prepared the following exhibits:

PECO Exhibit JAB-1 Revised	Revised Proposed Revenue Allocation and Rates of Return by Rate Class
PECO Exhibit JAB-2 Revised	Electric Service Tariff (Revised Pages Only)
PECO Exhibit JAB-3 Revised	Corrected Comparison of Residential Customer Charges for Pennsylvania Electric Distribution Utilities
PECO Exhibit JAB-4 Revised	Revised Proof of Revenue at Present and Proposed Rates
PECO Exhibit JAB-5 Revised	Revised Modified Base Rate Recovery of CAP Revenues in Universal Service Fund Charge
PECO Exhibit JAB-6	Response to Interrogatory PECO-OCA-II-13
PECO Exhibit JAB-7	Response to Interrogatory PECO-OCA-II-15
PECO Exhibit JAB-8	Response to Interrogatory PECO-SEPTA-II-1

5. Q. Do you have any revisions to your exhibits accompanying your direct testimony?

A. Yes. During the discovery process, the Company determined that PECO Exhibit JAB-3 listed its proposed residential customer charge as $14.25 instead of $14.28 in the comparison of customer charges among Pennsylvania electric distribution companies ("EDCs"). I have corrected this error in PECO Exhibit JAB-3 Revised.

In addition, PECO is revising its recommended change to the offset factor applied to reconcilable Customer Assistance Program ("CAP") costs recovered through PECO's Universal Services Fund Charge ("USFC") as discussed in the rebuttal testimony of Company witnesses Michael J. Trzaska (PECO Statement No. 3-R)

and Jacqueline F. Golden (PECO Statement No. 10-R). PECO Exhibits JAB-2 Revised and JAB-5 Revised reflect PECO's updated proposal for the USFC offset factor (12.1%), which represents a 1.6% increase from PECO's initial filing.

Finally, PECO Exhibits JAB-1 Revised and JAB-4 Revised incorporate the revisions summarized below.

II. REVENUE ALLOCATION

6. Q. Is the Company proposing any changes to its initial proposed revenue allocation presented in PECO Exhibit JAB-1?

A. Yes. PECO's revised revenue allocation is presented with my rebuttal testimony as PECO Exhibit JAB-1 Revised, along with a revised proof of revenues (PECO Exhibit JAB-4 Revised). These exhibits incorporate modifications to the Company's revenue requirement submitted by Company witness Michael J. Trzaska and revisions to the Company's electric cost of service study ("COSS") discussed by Company witness Tamara J. Jamison in her rebuttal testimony (PECO Statement No. 6-R). The most significant change brings the Lighting class to unity with its cost of service, while keeping its overall revenue increase below the system average and avoiding modifications to the Company's originally proposed location charges for lighting rate schedules SL-E, SL-C, AL, and TLCL. This in turn allowed the Company to slightly reduce the proposed revenue increase and variable distribution charges for commercial and industrial rate classes.

7. Q. Please summarize the other parties' alternative revenue allocation proposals.

A. OCA witness Johnson, PAIEUG witness LaConte, and SEPTA witness Crist express concerns with PECO's original proposal. The OCA's and PAIEUG's proposed alternative revenue allocations are based on Mr. Johnson's and Ms. LaConte's proposed modifications to PECO's COSS, respectively. Table 1 below shows the differences in the relative rates of return by rate class from PECO's revised allocation of revenues that would result from each opposing party's proposed revenue allocation.

Table 1: Proposed Relative Rates of Return by Rate Class (rounded to 0.XX)

Class	PECO Present Rates	PECO Original Proposal	PECO Revised Proposal	OCA	PAIEUG
Residential (R)	1.16	1.07	1.07	1.39	1.02
Residential Heating (RH)	0.59	0.82	0.82	0.43	0.78
General Service (GS)	0.92	0.96	0.96	0.56	1.04
Primary Distribution Power (PD)	0.76	0.90	0.89	0.76	1.02
High Tension (HT)	0.89	0.98	0.97	0.89	1.01
Electric Propulsion (EP)	0.57	0.73	0.72	0.57	0.88
Lighting	1.33	0.98	1.00	2.56	1.32

Walmart witness Perry does not oppose PECO's revenue allocation at its originally proposed revenue requirement and only recommends changes intended to reduce interclass subsidies if the Pennsylvania Public Utility Commission ("Commission") approves a revenue requirement lower than the Company's original proposal.

Mr. Johnson contends that the Company should allocate investments in its secondary distribution system on a purely demand basis. Due to the shift from a customer classification to a demand classification of secondary distribution system investments in Mr. Johnson's alternative COSS, the OCA proposes to assign substantially less revenue responsibility to the Residential class than either

PECO or the other parties. PECO witness Jamison addresses this issue in her rebuttal testimony. She explains that Mr. Johnson's approach is contrary to Commission precedent, while the Company's allocation of secondary distribution system costs on a customer basis is consistent with other EDCs in Pennsylvania and sound cost of service principles.

For her part, Ms. LaConte contends that PECO's COSS results diverge from prior rate cases due to "anomalous" non-coincident peak data. Ms. LaConte's recommended revenue allocation based on average historical load factors from PECO's previous rate cases should not be adopted for the reasons explained by Ms. Jamison. The Company's COSS therefore continues to be reflected in the revised revenue allocation proposed in PECO Exhibit JAB-1 Revised.

SEPTA witness Crist does not offer a comprehensive alternative revenue allocation. However, he contends that the Commission should approve a revenue allocation that would cap rate increases for Rate HT and EP at the overall increase ultimately granted to PECO.

8. Q. What is your general assessment of the opposing parties' recommendations?

A. There are many ways to allocate the increase that purport to give due consideration to valid cost of service indications and the principle of gradualism, as illustrated by the various proposals advanced in this case. Apart from the OCA's and PAIEUG's starting point with an alternative COSS, the other parties' proposed revenue allocations, while differing from each other and from PECO's original and revised allocations, generally used cost of service as the starting point and, as shown in Table 1, limited the percentage increase to any rate schedule to

less than 1.5 times the system average increase with the exception of the OCA's proposal for the Lighting class. Nonetheless, PECO believes its revised revenue allocation continues to provide an appropriate balance of the competing interests of all customer classes, producing reasonable movement toward the cost of service and system average rate of return indicated by the Company's revised COSS while also still reflecting the principle of gradualism.

9. Q. Mr. Johnson explains that he adjusted PECO's proposed rates so that no class receives an increase greater than 1.4 times the system average increase (Rate GS and RH) or 1.5 times the system average increase (all other classes). Do you agree?

A. In part. As stated in my direct testimony, I agree that gradualism is an accepted ratemaking principle that should be considered and applied in developing a utility's rate structure and revenue allocation. However, the gradualism considerations that I originally proposed and continue to support would allow for individual rate class increases of up to 2.0 times the system average increase, as opposed to 1.4 or 1.5 times that increase. As shown in PECO Exhibit JAB-6, Mr. Johnson himself has cited a prior Order in which the Commission previously acknowledged and accepted the use of a range of up to 2.0 times the system average in prior utility rate proceedings in the absence of definitive rules for determining the level of rate increase that would violate this principle. Mr. Johnson has therefore elected to limit this Commission-sanctioned range to the minimum and labeled it the Commission-sanctioned "cap" without providing evidence of that limit as being "frequently used" in Pennsylvania, admitting in the

process that he is not an expert with respect to Commission precedent. *See* PECO Exhibit JAB-6. I continue to support allowing flexibility up to the maximum of the Commission's range to support more effectively balancing gradualism with other ratemaking considerations.

10. Q. Mr. Johnson also recommends applying a 50% system average increase "floor" to the class revenue allocation. Do you agree with that proposal?

A. No. Mr. Johnson claims that his 50% "floor" suggestion is "cost-based" but defends it primarily based on equity, arguing that "all classes should share in the burden of the overall revenue increase." This implies that Mr. Johnson considers equity of greater importance to ratemaking than cost of service in this instance, and that all customer classes should always receive a revenue increase regardless of whether COSS results indicate that an increase for that class is financially warranted. As shown in Exhibit JAB-7, he describes this design as assigning substantially below-average revenue increases to classes paying more than their cost of service and, as a result, creating an "enhanced public acceptance" of the overall rate increase. This is antithetical to cost causation principles. Equity considerations, along with gradualism and others, are certainly valid concerns in balanced ratemaking, but I do not believe they should have priority over cost of service.

11. Q. Do you agree that revenue allocations to Rate HT and Rate EP should be reduced to no greater than the overall revenue increase approved by the Commission in this case, as Mr. Crist suggests?

A. No. Based on Mr. Crist's testimony, as well as his response to discovery provided in PECO Exhibit JAB-8, Mr. Crist provides no cost-based empirical support that demonstrates why the overall revenue increase for these rates should be capped at the system average.

III. SCALE BACK

12. Q. Have any of the parties proposed methods of scaling back PECO's proposed increases if the Commission grants less than the Company's requested revenue increase?

A. Yes. Mr. Sakaya, Mr. Johnson, Mr. Higgins, Ms. LaConte, and Ms. Perry each proposed scale back methodologies.

13. Q. If the Commission grants less than the Company's requested revenue increase, what do you think is the appropriate scale back methodology?

A. PECO recommends a proportional scale back of revenues relative to the approved increase as supported by Mr. Higgins (OSBA St. No. 1, p. 11), Mr. Johnson (OCA St. No. 3, p. 23) and Ms. LaConte (PAIEUG St. No. 1, p. 16), but opposes inclusion of the Company's proposed residential customer charge increase in that scale back. The proposed monthly customer charge is supported by the Company's customer cost analysis and better approximates the total customer-related costs that PECO incurs, as explained in Ms. Jamison's rebuttal testimony.

14. Q. Please summarize Mr. Sakaya's and Ms. Perry's targeted scaleback proposals.

A. Mr. Sakaya recommends that the Company implement a targeted scale back totaling $95.7 million incorporating different scale back levels. Mr. Sakaya states that this targeted scale back will move the relative rate of return for most classes toward 1.0. Similarly, Walmart witness Perry recommends that PECO apply 50% of the overall revenue reduction to those rate classes with relative rates of return above 1.0 with the remaining 50% distributed equally among all classes.

15. Q. Why do you disagree with these approaches?

A. By design, these approaches do not scale back the proposed increases uniformly relative to the Company's proposed increase. They solely favor additional movement toward cost-based allocations. The Company supports a proportional scale back because it more equitably treats all customer classes based directly on the amount of any reduction along with the cost-based allocations and gradualism concerns determined to be reasonable prior to the reduction granted through a scale back. PECO therefore continues to support a proportional scale back, excluding the proposed increase to the residential customer charge.

IV. CUSTOMER CHARGES

16. Q. Witnesses on behalf of the OCA and TURN/CAUSE-PA have opposed PECO's proposed increase in its residential customer charge because they contend it will harm low-income customers. Do you agree?

A. No. If PECO's residential customer charge remains at its current level, the entire rate increase would have to be recovered through a volumetric (kWh) charge.

That approach would actually be worse for PECO's low-income customers than the Company's proposal. PECO analyzed the impact on its low-income electric customers of increasing the residential customer charge from $10.50 to $14.28 as PECO proposes. Table 2 below presents the results of the Company's analysis using average monthly 2023 sales data (for Customer Assistance Program ("CAP") customers and non-CAP confirmed low-income customers) and rates in effect as of July 1, 2024.

Table 2 – Rate Design Impact on PECO Low-Income Customers

	Federal Poverty Level ("FPL")	2023 Monthly Average Usage	Proposed PECO Rate R, $14.28 Cust Charge Plus VDC $0.9418/kWh	Modified Proposed PECO Rate R, $10.50 Cust Charge Plus $0.09995/kWh	$ Diff	% Diff
CAP	0% - 25%	808	$176.01	$176.89	$0.88	0.5%
	25% - 50%	762	$166.80	$167.42	$0.62	0.4%
	51% - 100%	647	$143.80	$143.75	($0.05)	0.0%
	101% - 150%	640	$142.40	$142.31	($0.09)	-0.1%
	151% - 200%	902	$194.82	$196.24	$1.43	0.7%
	Unknown	736	$161.60	$162.06	$0.46	0.3%
Non-CAP Confirmed Low-Income	0% - 25%	665	$147.40	$147.46	$0.06	0.0%
	25% - 50%	711	$156.59	$156.91	$0.32	0.2%
	51% - 100%	640	$142.40	$142.31	($0.09)	-0.1%
	101% - 150%	656	$145.59	$145.60	$0.01	0.0%
	151% - 200%	667	$147.80	$147.86	$0.06	0.0%
	Unknown	686	$151.60	$151.77	$0.17	0.1%

The data presented in Table 2 demonstrates that the cost impact of the proposed change in the residential customer charge is not material (between -0.1% and 0.7%). However, most of PECO's low-income electric customers would pay more if the revenue increase were applied on a volumetric basis as compared to the Company's proposed increase in the customer charge.

17. Q. Please respond to assertions that the Company's proposed residential charge will negatively impact energy efficiency and undermine Low-Income Usage Reduction Program ("LIURP") goals.

A. PECO considered the impact that an increase in the residential customer charge could have on both lower-usage and higher-usage residential customers in developing all elements of its rate structure and rate design, consistent with prior Commission precedent that the customer charge should be considered in the context of the entire increase for a rate class. Any division of costs between fixed and volumetric rate components within a rate class will have relative winners and losers. PECO believes that its proposal to provide a relative benefit to higher-usage low-income customers, who are more likely to experience high monthly bills and therefore would benefit more from lessening the impact of the overall rate increase, is reasonable. PECO witness Jacqueline F. Golden addresses bill affordability for low-income customers.

OCA witnesses Johnson and Colton appear to favor equitable treatment of lower-usage, low-income customers, based on their contention that low-income customers residing in PECO's service area are more likely to be lower-usage customers than higher-usage customers. However, as shown in Table 2 above, the increase in PECO's residential customer charge will not have a material adverse impact on low-income customers with the lowest average monthly usage.

In addition, Mr. Colton does not support his assertions that the Company's proposed increase to the residential customer charge will impair efficiency efforts or undermine the Company's LIURP. He presents no evidence backing his

claims that a customer charge increase will directly lead to low-income customers either reducing efforts to pursue usage-reduction measures or, conversely, to those customers pursuing "more dangerous" measures. Finally, Mr. Colton's comparisons in the charge to the Low Income Home Energy Assistance Program ("LIHEAP") are irrelevant. LIHEAP is a federal program and PECO is not involved in the establishment of LIHEAP funding levels.

18. Q. Please summarize the reasons why you believe the Company's proposed residential customer charge is appropriate.

As explained in my direct testimony, the $14.28 residential customer charge proposed by the Company will be closer to, but still less than, the customer-related costs identified by Ms. Jamison in PECO Exhibit TJJ-4. PECO's proposal to increase the residential customer charge will also provide a relative benefit to high-usage, low-income customers by lessening the impact of the overall rate increase on customers that are more likely to experience high monthly bills. Furthermore, the data presented in Table 2 shows that applying the increase entirely to volumetric charges is more likely to harm rather than help the Company's low-income customers. PECO therefore continues to consider its proposed increase to the residential customer charge as both well supported and reasonable.

V. CONCLUSION

19. Q. Does this complete your rebuttal testimony at this time?

A. Yes, it does.

"Electric Proposed Revenue Increase by Class" Matrix

Supports Exhibit JAB-1 (Revenue Allocation)

Sys Average Rate of Return (RRM A-1): 7.98%

Gross Revenue Conversion Factor (RRM A-1): 1.476

	($000's) Rate Base (COS)	($000's) Initial COS Increase at Sys Average ROR (COS)	Proposed Relative ROR (Input)	Adjusted Proposed Rate of Return	ROR Variance from Sys Avg ROR	COS Adjustment	($000's) Adjusted COS Increase at Proposed Relative ROR (COS)	($000's) Net Revenue Ask at Proposed Relative ROR	($000's) Current Adjusted Distribution Revenue (Proof of Revenues)	($000's) Proposed Adjusted Distribution Revenue (Proof of Revenues)
R	$ 4,506,469	$ 188,222	1.07	8.58%	-0.60%	-0.88%	$ (39,815)	$ 228,038	$ 927,198	$ 1,155,236
RH	$ 1,181,480	$ 93,996	0.82	6.58%	1.40%	2.06%	$ 24,358	$ 69,638	$ 177,985	$ 247,623
GS	$ 1,698,851	$ 97,928	0.96	7.64%	0.34%	0.51%	$ 8,603	$ 89,325	$ 266,019	$ 355,343
PD	$ 47,950	$ 3,281	0.89	7.06%	0.92%	1.35%	$ 649	$ 2,632	$ 7,647	$ 10,279
HT	$ 1,179,536	$ 70,728	0.97	7.73%	0.25%	0.37%	$ 4,374	$ 66,355	$ 178,267	$ 244,621
EP	$ 56,810	$ 4,594	0.72	5.71%	2.27%	3.36%	$ 1,907	$ 2,687	$ 7,059	$ 9,746
Lighting	$ 129,417	$ 4,050	1.00	8.02%	-0.04%	-0.06%	$ (75)	$ 4,124	$ 25,034	$ 29,159
Summary	$ 8,800,513	$ 462,798						$ 462,798	$ 1,589,208	$ 2,052,007

PECO Energy Company (Electric)
Revised Revenue Allocation and Rates of Return by Rate Class

Rate Class	(1) Current Distribution Revenue	(2) Proposed Distribution Revenue	(3) *(2) - (1)* Distribution Revenue Ask	(4) 2024 GSA / TSC Working Capital Adjustment	(5) *(3) + (4)* Net of 2024 GSA/TSC Adjustment	(6) *(5) / (1)* % Increase	(7) Increase vs. System Avg
Residential (R)	$ 927,197,917	$ 1,155,235,651	$ 228,037,734	$ (2,449)	$ 228,035,285	24.6%	0.84
Residential Heating (RH)	$ 177,984,866	$ 247,622,971	$ 69,638,105	$ 52,626	$ 69,690,731	39.2%	1.35
General Service (GS)	$ 266,018,693	$ 355,343,253	$ 89,324,560	$ (85,924)	$ 89,238,636	33.5%	1.15
Primary Distribution (PD)	$ 7,647,292	$ 10,279,206	$ 2,631,914	$ (5,686)	$ 2,626,228	34.3%	1.18
High Tension (HT)	$ 178,266,580	$ 244,621,316	$ 66,354,736	$ (194,071)	$ 66,160,665	37.1%	1.28
Electric Propulsion (EP)	$ 7,058,589	$ 9,745,598	$ 2,687,009	$ (4,021)	$ 2,682,988	38.0%	1.31
Lighting	$ 25,034,326	$ 29,158,635	$ 4,124,309	$ (529)	$ 4,123,780	16.5%	0.57
Total	$ 1,589,208,263	$ 2,052,006,630	$ 462,798,367	$ (240,054)	$ 462,558,313	29.1%	

Rate Class	(8) Present Rate of Return	(9) *(8) / Average of (8)* Present Relative Rate of Return	(10) Proposed Rate of Return	(11) *(10) / Average of (10)* Proposed Relative Rate of Return
Residential (R)	5.15%	1.17	8.58%	1.07
Residential Heating (RH)	2.59%	0.59	6.58%	0.82
General Service (GS)	4.08%	0.92	7.64%	0.96
Primary Distribution (PD)	3.35%	0.76	7.06%	0.89
High Tension (HT)	3.93%	0.89	7.73%	0.97
Electric Propulsion (EP)	2.51%	0.57	5.71%	0.72
Lighting	5.86%	1.33	8.02%	1.00
Total	4.42%		7.98%	

PECO Energy Company

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PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC)

Variable Distribution Service Charge rates for electric service in Residential Rate Schedule R and RH of this Tariff shall include a charge of $0.00685 per kWh for recovery of Universal Service Fund Cost (USFC), calculated in the manner set forth below pursuant to Section 2804 (8) of the Competition Act. The USFC rate for electric service shall be increased or decreased annually, to reflect changes in the level of Universal Service Fund costs, net of base rate recoveries, in the manner described below:

COMPUTATION OF USFC.
The USFC per kWh ($0.0000), shall be computed in accordance with the formula set forth below:

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

The USFC, so computed, shall be included in distribution rates charged to Customers for service pursuant to the rate schedules identified above. The amount of USFC, per kWh, will vary, if appropriate, based upon annual filings by the Company.

In computing the USFC, per kWh, pursuant to the formula above, the following definitions shall apply:

Reconcilable Customer Assistance Program (CAP) Costs – The difference between discounts provided to CAP customers (CAP revenue shortfalls) recovered through base rates and total CAP discounts, net of a 12.1% 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. This shall include expenditures for LIURP Health and Safety programming.

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. The interest calculation will not apply to LIURP amounts.

S - projected kWh of electric service to be billed under Rate R and Rate RH (exclusive of CAP Rider) during the projected period when rates will be in effect.

FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECONCILIATION.
The Company's annual USFC filing and its annual reconciliation statement shall be submitted to the Commission 120 days prior to new rates being effective January 1 of each year, or at such time as the Commission may prescribe. The USFC mechanism is subject to annual audit review by the Bureau of Audits.

Issued July 16, 2024

Effective XXX XX, XXXX

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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.¶
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PECO Energy Company

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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: $14.30
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $2.77

VARIABLE DISTRIBUTION SERVICE CHARGE:
All kWhs $0.10325 per kWh

ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

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

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

PAYMENT TERMS. Standard.

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PECO Energy Company

Tariff Electric Pa. P.U.C. No. 8
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RATE RH RESIDENTIAL HEATING SERVICE

AVAILABILITY.

Single phase service to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for domestic requirements when such service is provided through one meter and where the dwelling is heated by specified types of electric space heating systems. The systems eligible for this rate are (a) permanently connected electric resistance heaters where such heaters supply all of the heating requirements of the dwelling, (b) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by electric resistance heaters, and (c) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by non electric energy sources. All space heating installations must meet Company requirements. This rate schedule is not available for commercial, institutional or industrial establishments.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date, must be individually metered

CURRENT CHARACTERISTICS. Standard single phase secondary service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $14.30
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $2.77

VARIABLE DISTRIBUTION SERVICE CHARGE:

SUMMER MONTHS. (June through September)
$0.10325 per kWh for all kWh.
WINTER MONTHS. (October through May)
$0.08416 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, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND CONSERVATION PROGRAM COSTS 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-GS GENERAL SERVICE

AVAILABILITY.
Service for offices, professional, commercial or industrial establishments, governmental agencies, farms and other applications outside the scope of the Residence Service rate schedules.

Transformed service from the Company's distribution system where the company installs, owns, and maintains any transforming, switching and other receiving equipment required.

For service configurations that are nominally 120/208 volts, 3 phase, 4 wires – If either the service capacity or the parallel-generating capacity exceeds 750 kVA for transformers located inside the building, the only rate option available to the customer will be Rate HT. If either the service capacity or the parallel-generating capacity exceeds 750 kVA but remains at or below 1,500 kVA for transformers outside the building, the customer may request service at 277/480 volts, 3-phase 4-wires from transformers located outside the building. Otherwise the only rate option available to the customer will be Rate HT.

For service configurations that are nominally 277/480 volts, 3 phase, 4 wires - If either the service capacity or the parallel-generating capacity exceeds either 750 kVA for transformers located inside the building or 1,500 kVA for transformers located outside the building, the only rate option available to the customer will be Rate HT.

CURRENT CHARACTERISTICS.
Standard single-phase or polyphase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE:
$24.47 for single-phase service without demand measurement, or
$31.20 for single-phase service with demand measurement, or
$74.66 for polyphase service.

VARIABLE DISTRIBUTION SERVICE CHARGE:
$12.08 per kW of billed demand

($0.0006) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: $0.00458 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and ¾.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand may be measured where consumption exceeds 1,100 kilowatt-hours per month for three consecutive months; or where load tests indicate a demand of five or more kilowatts; or where the customer requests demand measurement. Measured demands will be determined to the nearest 0.1 of a kilowatt but will not be less than 1.2 kilowatts, and will be adjusted for power factor in accordance with the Rules and Regulations.
For those customers with demand measurement the billing demand will be determined as follows:
(a) For customers with demand up to 500 kW, the billing demand shall be the measured demand, with a minimum billing demand of 1.2 kW.
(b) For customers with measured demand or maximum 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, plus the Variable Distribution Service Charge per KW of minimum billing demand as described above. The monthly minimum charge for customers with demand measurement will be the Fixed Distribution Service Charge, plus per KW of billing demand. In addition to the above, for customers in Procurement Class ¾ charges will be assessed on PJM's reliability pricing model.

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RATE-PD PRIMARY DISTRIBUTION POWER

AVAILABILITY.
Untransformed service from the primary supply lines of the Company's distribution system where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required. However, standard primary service is not available in areas where the distribution voltage has been changed to either 13 kV or 33 kV unless the customer was served with standard primary service before the conversion of the area to either 13 kV or 33 kV. This rate is available only for service locations served on this rate on July 6, 1987 as long as the original primary service has not been removed. PECO Energy may refuse to increase the load supplied to a customer served under this rate when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist. If a customer changes the billing rate of a location being served on this rate, PECO Energy may refuse to change that location back to Rate PD when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist.

CURRENT CHARACTERISTICS.
Standard primary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $297.61

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VARIABLE DISTRIBUTION SERVICE CHARGE:
$12.05 per kW of billing demand
($0.0006) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: $0.53 per kW of Peak Load Contribution

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

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DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. The 25kW minimum shall apply to the Energy Supply Charge and the Transmission Supply Charge. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract.

MINIMUM CHARGE.
The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, plus in the case of Procurement Class 3/4 customers, charges assessed under PJM's reliability pricing model.

TERM OF CONTRACT.
The initial contract term shall be for at least three years.

PAYMENT TERMS.
Standard.

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RATE-HT HIGH TENSION POWER

AVAILABILITY.
Untransformed service from the Company's standard high tension lines, where the customer installs, owns, and maintains, any transforming, switching and other receiving equipment required.

CURRENT CHARACTERISTICS.
Standard high tension service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $371.68

VARIABLE DISTRIBUTION SERVICE CHARGE:
$7.77 per kW of billing demand
($0.0006) per kWh for all kWh

HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For customers supplied at 33,000 volts: $0.26 per kW of measured demand.
For customers supplied at 69,000 volts: $2.11 per kW of measured demand.
For customers supplied over 69,000 volts: $2.11 per kW of measured demand.

ENERGY EFFICIENCY CHARGE: $0.53 per kW of Peak Load Contribution

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND CONSERVATION PROGRAM AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract. The 25 kW minimum shall apply to the Energy Supply Charge and the Transmission Supply Charge.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS.
If the load of a customer located at a delivery point becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer at that delivery point, upon the written request of the customer, the Company will establish a new delivery point and bill the customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point and provided that such multi-point delivery is not disadvantageous to the Company.

MINIMUM CHARGE.
The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, and modify less the high voltage discount where applicable plus in the case of Procurement Class 3/4 customers, charges assessed on PJM's reliability pricing model.

TERM OF CONTRACT.
The initial contract term shall be for at least three years.

PAYMENT TERMS.
Standard.

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RATE EP ELECTRIC PROPULSION

AVAILABILITY.
This rate is available only to the National Rail Passenger Corporation (AMTRAK) and to the Southeastern Pennsylvania Transportation Authority (SEPTA) for untransformed service from the Company's standard high tension lines, where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required and where the service is provided for the operation of electrified transit and railroad systems and appurtenances. Rate EP is also available to legacy transformed service that is receiving service pursuant to Rate EP as of January 1, 2020; Rate EP or successor rates shall remain available for such legacy transformed service until at least December 31, 2040.

CURRENT CHARACTERISTICS.
Standard sixty hertz (60 Hz) high tension service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $1,292.35 per delivery point

VARIABLE DISTRIBUTION SERVICE CHARGE:
$6.73 per kW of billing demand
($0.0006) per kWh for all kWh

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HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For delivery points supplied at 33,000 volts: $0.26 per kW.
For delivery points supplied at 69,000 volts: $2.15 per kW for first 10,000 kW of measured demand.
For delivery points supplied over 69,000 volts $2.15 per kW for first 100,000 kW of measured demand.

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ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class ¾.

ENERGY EFFICIENCY CHARGE: $0.53 per kW of Peak Load Contribution

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

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DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 5,000 kilowatts. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS.
If the load of a customer located at a delivery point becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer at that delivery point, upon the written request of the customer, the Company will establish a new delivery point and bill the customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point and provided that such multi-point delivery is not disadvantageous to the Company. Conjunctive billing under this section is available regardless of whether the conjunctively-billed sites take generation service from one or more generation suppliers and/or PECO default service.

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RATE POL PRIVATE OUTDOOR LIGHTING

AVAILABILITY.
To any residential or commercial customer with outdoor lighting of sidewalks, driveways, yards, lots and similar places, outside the scope of service under Rates SL-S and SL-E.

MONTHLY RATE TABLE.
A Standard Lighting Unit shall be a Cobra Head or Floodlight comprised of a bracket, the lead wires, and a luminaire, including lamp, reactor, and control. The wattage is composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls, and other load components required for its operation

MERCURY-VAPOR LAMPS	PRICE PER LIGHTING UNIT DISTRIBUTION (Co.Pole)	(Cust.Pole)
100 Watts (nominally 4,000 Lumens)	$15.02	$12.85
175 Watts (nominally 8,000 Lumens)	$22.25	$20.19
250 Watts (nominally 12,000 Lumens)	$28.65	$26.81
400 Watts (nominally 20,000 Lumens)	$38.45	$36.01
400 Watts Floodlight (nominally 22,000 Lumens)	$42.08	$39.64

SODIUM-VAPOR LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
70 Watts (nominally 5,800 Lumens)	$22.64	$20.53
250 Watts (nominally 25,000 Lumens)	$39.07	$36.63
400 Watts (nominally 50,000 Lumens)	$43.20	$40.75
400 Watts Floodlight (nominally 50,000 Lumens)	$46.81	$44.37

Service to the above listed Mercury-Vapor Lamps and Sodium-Vapor Lamps is not available as of January 1, 2016 to new Customers or existing customers for new or replacement luminaires. The Company will not replace defective or broken mercury vapor or sodium vapor luminaires, including ballasts. In such cases, the customer must take service under one of the current lighting unit options as set forth below.

METAL HALIDE LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
100 Watts (nominally 7,800 Lumens)	$36.25	$34.88
175 Watts (nominally 13,000 Lumens)	$38.28	$35.72
250 Watts (nominally 20,500 Lumens)	$40.79	$38.26
400 Watts (nominally 36,000 Lumens)	$46.02	$43.63
1000 Watts (nominally 110,000 Lumens)	$84.11	$81.78

HIGH PRESSURE SODIUM VAPOR LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
50 Watts (nominally 4,000 Lumens)	$22.47	$20.33
70 Watts (nominally 5,800 Lumens)	$26.17	$23.80
100 Watts (nominally 9,500 Lumens)	$27.92	$25.57
150 Watts (nominally 16,000 Lumens)	$30.96	$28.60
250 Watts (nominally 25,000 Lumens)	$37.19	$34.78
400 Watts (nominally 50,000 Lumens)	$46.10	$43.71
1,000 Watts (nominally 130,000 Lumens)	$53.84	$52.91

LIGHT-EMITTING DIODE LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
35 Watts (nominally 3,300 Lumens)	$40.36	$38.14
53 Watts (nominally 5,000 Lumens)	$41.49	$39.26
87 Watts (nominally 8,300 Lumens)	$43.01	$40.79
163 Watts (nominally 15,800 Lumens)	$47.26	$45.03
215 Watts (nominally 20,000 Lumens)	$49.80	$47.58

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

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, NON-BYPASSABLE TRANSMISSION CHARGE, CONSERVATION PROGRAM COSTS AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

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PECO Energy Company

Tariff Electric Pa. P.U.C. No. 8
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RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES

AVAILABILITY.
To any municipal entity for outdoor lighting of streets, highways, bridges, parks and similar places located outside the city and county of Philadelphia, including directional highway signs at locations where other outdoor lighting service is established hereunder, only if all of the distribution facilities and equipment are installed, owned, and maintained by the Company.

ANNUAL RATE TABLE
The prices in the Rate Table apply to all Company-approved installations for (a) federal, state, county and municipal authorities and community associations entering into a contract for lighting service; and (b) building operation developers for lighting, during the development period, of streets that are to be dedicated, where the municipality has approved the lighting and agreed to subsequently assume the charges for it under a standard contract.

The wattage is composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls, and other load components required for its operation.

Incandescent Filament Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
320 Lumens	32	$128.82
600 Lumens	58	$183.79
1,000 Lumens	103	$259.20
2,500 Lumens	202	$359.23
6,000 Lumens	448	$409.07
10,000 Lumens	690	$496.14

Mercury Vapor Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
4,000 Lumens	115	$306.53
8,000 Lumens	191	$323.58
12,000 Lumens	275	$344.91
20,000 Lumens	429	$405.65
42,000 Lumens	768	$579.91
59,000 Lumens	1,090	$652.71

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	$304.34
9,500 Lumens	131	$331.38
16,000 Lumens	192	$372.78
25,000 Lumens	294	$423.97
50,000 Lumens	450	$505.83

Light-Emitting Diode Lamps Size of Lamp (Nominal)

	Billing Watts	Distribution
3,300 Lumens	35	$542.65
5,000 Lumens	53	$556.33
8300 Lumens	87	$574.45
15,800 Lumens	163	$625.47
20,000 Lumens	215	$656.04

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

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT, APPLY TO THIS RATE.

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PECO Energy Company

Tariff Electric Pa. P.U.C. No. 8
Original Page No. 66

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:	$7.49 per Service Location (as defined below) *
VARIABLE DISTRIBUTION CHARGE:	$0.02500 per kWh

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

* The service location charge includes an Energy Efficiency Program Surcharge ($0.08) per location.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.
A Service Location is the Point of Delivery on the Company's secondary circuit. That connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company.

DETERMINATION OF ENERGY BILLED.
The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules as set forth under Terms and Conditions, Paragraph 1 Service. The wattage, expressed to the nearest tenth of a watt, of a Service Location shall be composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls and other load components required for its operation. The aggregate of the kilowatt hours thus computed for all Active Service Locations shall constitute the energy billed for the month.

TERMS AND CONDITIONS.

1. Service. Lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer

2. Ownership of Utilization Facilities.

a. Service Locations Supplied from Aerial Circuits: customer shall provide, own and maintain the Utilization Facilities defined as the brackets, hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, conductors, molding and supporting insulators between the lamp receptacles and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location.
The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities. If the Company sells aerially supplied streetlighting facilities to a government agency in order to qualify for SL-E, such sale will include the supporting pole or post.

b. Service Locations Supplied from Underground Circuits: customer shall provide, own and maintain the Utilization Facilities defined as brackets or hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, and conductors and shall assume all costs of installing such Utilization Facilities. Customer shall also provide, own, and maintain the supporting pole or post foundation with 90 degree pipe bend, and conduits from the luminaires to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a Service Location designated by the Company on its secondary voltage circuit.
Except as provided in Paragraph 5 Supply Facilities, the Company shall own conduit from the distribution circuit to the 90 degree pipe bend, shall own conductors from its distribution system to the designated Service Location and shall provide sufficient length of conductors for splicing at the designated Service Location or in the post base where sidewalk level access is provided.

c. Service to Group of Utilization Facilities:

AERIAL SUPPLY
When the customer requests service to a group of Utilization Facilities supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the Utilization Facilities. The Company will provide a service, nominally 100 feet, to the customer's first supporting structure. The customer is responsible for installing supply conductors from the first supporting structure to all Utilization Facilities.

UNDERGROUND SUPPLY
When groups of Utilization Facilities are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each Utilization Facility from the designated Service Location. If the customer requests an underground supply to a group of Utilization Facilities and the designated Service Location is a secondary terminal pole, the customer will install, own, maintain all cable, including the cable on the pole.

3 .Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

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PECO Energy Company

Tariff Electric Pa. P.U.C. No. 8
Original Page No. 68

RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.
Any governmental agency for outdoor lighting, provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, that complies with each of the following conditions:

(A) Installs a Smart Lighting Control Module approved by the Company that has capabilities including but not necessarily limited to:
a. Measurement of energy usage at the individual Utilization Facility level.
b. Customer control of the lamp's burning hours.
c. Data showing failure of the lamp to burn, such as customer notification, that customer can provide to Company upon request.
d. Ability of customer to dim the lights (LED only).
(B) Provides energy usage to the Company as described below under Data Requirements.
(C) Installs, owns, and maintains all Utilization Facilities, as defined in the Terms and Conditions of this Base Rate. (All facilities and their installation shall be approved by the Company.)

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers.

Customers may take service under the rate beginning on July 1, 2019. The below listed pricing will be revised, as needed, based on applicable surcharge adjustments prior to the SL-C effective service date of July 1, 2019.

MONTHLY RATE TABLE.
SERVICE LOCATION DISTRIBUTION CHARGE: $6.34 per Service Location (as defined below)*
VARIABLE DISTRIBUTION CHARGE: $0.04692 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 ($0.07) per location.

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

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.
A Service Location is the Point of Delivery on the Company's secondary circuit that connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company

DATA REQUIREMENTS.
The customer must notify the Company of its intent to enroll or modify lights under this rate at least 30 days prior to the start of the regularly scheduled billing cycle during which the enrollment or modification will become effective.

The customer must provide the following data to the Company from its Company-approved Smart Lighting Control Module for each light added or modified:
8. Manufacturer-rated wattage
9. Annual burning hours, if different than the standard 4,100 burning hours as defined below under paragraph 1 Service of Terms and Conditions
10. Dimming percentage/factor

The Company also requires the customer to provide the Global Positioning System (GPS) coordinates for each light.

DETERMINATION OF ENERGY BILLED.
Upon acceptance of the required data, the Company shall modify the energy billed going forward for a period of up to twelve months or at another frequency as required by the Company. The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage, adjusted based on the provided dimming percentage/factor, and the provided burning hours during the calendar month.

The Company may, at any time and without prior notice, request that the customer provide updates to the above data or provide actual energy consumption data and burning hours for each light, by calendar month, for up to the past 12 months to verify the continued accuracy of Company billing.

For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, the Company shall modify the energy billed going forward by changing the burning hours used to the standard 4,100 burning hours as defined below under Paragraph 1 Service of Terms and Conditions.

The Company reserves the right to modify the customer's rate to SL-E in the continued absence of required data from the customer.

TERMS AND CONDITIONS.
1. Service. For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer. If the customer provides information from the Smart Lighting Control Module as described above to justify a different billing usage, the burning hours provided by the customer will be used instead of the standard 4,100 annual operating hours.

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RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE

AVAILABILITY.
To any municipality using the Company's standard service for (a) electric traffic signal lights installed, owned and maintained by the municipality, and/or (b) unmetered traffic control cameras or other small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the municipality.
To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically separate from any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account.
To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically integrated with any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account, but only if the non-municipal customer meets the conditions of the Special Termination Rights provision of this Rate.

CURRENT CHARACTERISTICS.
Standard single phase secondary service.

RATE TABLE.
SERVICE LOCATION CHARGE: $4.08 PER LOCATION

VARIABLE DISTRIBUTION SERVICE CHARGE: $0.02225 per kWh (as defined below)*
*The Variable Distribution charge includes an Energy Efficiency Program Surcharge of ($0.00081) 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, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, NON-BYPASSABLE TRANSMISSION CHARGE, CONSERVATION PROGRAM COSTS, FIBER AFFILIATE REVENUE SURCHARGE, INCREMENTAL COVID-19 RELATED UNCOLLECTIBLE SURCHARGE 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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PECO Energy Company

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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: $24.56

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Charge per kW of Off-Peak billing demand per month: $4.16

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STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), 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: $11.45
Charge per kW of Off-Peak billing demand:
$3.51 per month for Rate HT.
$3.21 per month for Rate EP.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) APPLIES TO THIS RIDER.

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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.

NIGHT SERVICE PD RIDER

AVAILABILITY/APPLICABILITY.
To distribution service provided during Off-Peak Hours for demands in excess of those supplied during On-Peak Hours. The demand specified for Off-Peak Hours shall be limited to an amount determined by the Company which shall be dependent upon the capacity of the generation, trademark and distribution facilities available for such supply.

DEFINITION OF PEAK HOURS.
On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the On-Peak Hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as On-Peak Hours.

RATE IMPACT.
Rate PD, including all terms and guarantees, is applicable during On-Peak Hours. If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

MONTHLY RATE TABLE.

Night Service billing and metering charge: $11.45
Charge per kW of Off-Peak billing demand per month: $4.79

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) 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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Comparison of Residential Customer Charges for Pennsylvania Electric Distribution Utilities

Company	**Current Base Residential Customer Charge**
Citizens Electric	$ 13.10
Duquesne	$ 12.50
MetEd	$ 11.25
Pennelec	$ 11.25
Penn Power	$ 11.00
PPL	$ 14.09
UGI	$ 10.75
West Penn	$ 7.44
PECO Current	**$ 10.50**
PECO Proposed	**$ 14.28**

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Residential (R)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	16,065,289	$ 10.50	$ 168,685,535	$ 14.28	$ 229,412,327
3	Second Meter	758,520	$ 2.04	$ 1,547,381	$ 2.77	$ 2,101,100
4						
5	**Total Customer Charge Revenue**			$ 170,232,916		$ 231,513,427
6						
7	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	Base Rate	11,367,080,835	$ 0.07094	$ 806,380,714	$ 0.09418	$ 1,070,515,359
9						
10	CAP Credits - Distribution			$ (53,151,989)		$ (70,562,229)
11	CAP Credits - Non-Distribution			$ (77,783,810)		$ (77,783,810)
12	CAP Shortfall			$ 42,765,821		$ -
13						
14	Distribution System Improvement Charge (DSIC)			$ 37,176,685		$ -
15						
16	**Total Variable Distribution Revenue**			$ 755,387,421		$ 922,169,320
17						
18	Regulatory Initiatives			$ 1,687,669		$ 1,687,669
19	Load Reduction			$ (1,929,512)		$ (2,404,922)
20	Annualization			$ 1,819,423		$ 2,267,708
21						
22						
23	**Adjusted Total Distribution Revenue**			$ 927,197,917		$ 1,155,233,202

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Residential Heating (RH)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	2,452,036	$ 10.50	$ 25,746,378	$ 14.28	$ 35,015,074
3						
4	**Total Customer Charge Revenue**			$ 25,746,378		$ 35,015,074
5						
6	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Base Rate, June-September	723,464,828	$ 0.07094	$ 51,322,595	$ 0.09418	$ 68,133,606
8	Base Rate, October-May	2,169,214,681	$ 0.05111	$ 110,868,562	$ 0.07472	$ 162,088,858
9						
10	CAP Credits - Distribution			$ (6,485,920)		$ (9,482,358)
11	CAP Credits - Non-Distribution			$ (9,491,641)		$ (9,491,641)
12	CAP Shortfall			$ (2,149,445)		$ -
13						
14	Distribution System Improvement Charge (DSIC)			$ 7,050,907		$ -
15						
16	**Total Variable Distribution Charge Revenue**			$ 151,115,058		$ 211,248,465
17						
18	Regulatory Initiatives			$ 387,904		$ 387,904
19	Load Reduction			$ (403,528)		$ (561,876)
20	Annualization			$ 1,139,054		$ 1,586,030
21						
22	**Adjusted Total Distribution Revenue**			$ 177,984,866		$ 247,675,597

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - General Service (GS)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Single-Phase - No Demand	373,531	$ 18.99	$ 7,093,361	$ 24.47	$ 9,140,313
3	Single-Phase - With Demand	1,099,420	$ 24.21	$ 26,616,967	$ 31.20	$ 34,301,916
4	Poly-Phase - With Demand	405,813	$ 57.94	$ 23,512,819	$ 74.66	$ 30,298,016
5	GS Night Service Rider	34,963	$ 19.06	$ 666,386	$ 24.56	$ 858,680
6						
7	**Total Customer Charge Revenue**			$ 57,889,533		$ 74,598,925
8						
9	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
10	Base Rate	7,546,791,990	$ (0.0006)	$ (4,528,075)	$ (0.0006)	$ (4,528,075)
11						
12	**Total kWh-Based Variable Distribution Revenue**			$ (4,528,075)		$ (4,528,075)
13						
14	**kW-Based Variable Distribution Charges**	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
15	Base Rate	24,820,966	$ 8.12	$ 201,546,247	$ 11.48	$ 284,865,721
16	GS Night Service Rider	119,862	$ 2.94	$ 352,394	$ 4.16	$ 498,075
17						
18	**Total kW-Based Variable Distribution Revenue**			$ 201,898,641		$ 285,363,796
19						
20	Distribution System Improvement Charge (DSIC)			$ 10,879,090		$ -
21						
22	**Total Variable Distribution Charge Revenue**			$ 208,249,656		$ 280,835,721
23						
24	Regulatory Initiatives			$ 48,855		$ 48,855
25	Load Reduction			$ (891,550)		$ (1,190,684)
26	Annualization			$ 722,199		$ 964,512
27						
28	**Adjusted Total Distribution Revenue**			$ 266,018,693		$ 355,257,329

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Primary Distribution (PD)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	4,608	$ 295.94	$ 1,363,692	$ 297.61	$ 1,371,387
3	PD Night Service Rider	1,524	$ 11.39	$ 17,358	$ 11.45	$ 17,456
4						
5	**Total Customer Charge Revenue**			$ 1,381,050		$ 1,388,843
6						
7	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	Base Rate	290,809,752	$ (0.0006)	$ (174,486)	$ (0.0006)	$ (174,486)
9						
10	**Total kWh-Based Variable Distribution Revenue**			$ (174,486)		$ (174,486)
11						
12	**kW-Based Variable Distribution Charges**	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
13	Base Rate	739,905	$ 8.27	$ 6,119,017	$ 12.25	$ 9,060,178
14	PD Night Service Rider	2,851	$ 3.03	$ 8,639	$ 4.49	$ 12,801
15						
16	**Total kW-Based Variable Distribution Revenue**			$ 6,127,656		$ 9,072,979
17						
18	Distribution System Improvement Charge (DSIC)			$ 323,351		$ -
19						
20	**Total Variable Distribution Charge Revenue**			$ 6,276,521		$ 8,898,493
21						
22	Regulatory Initiatives			$ 20		$ 20
23	Load Reduction			$ (12,941)		$ (17,385)
24	Annualization			$ 2,642		$ 3,549
25						
26	**Adjusted Total Distribution Revenue**			$ 7,647,292		$ 10,273,520

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - High Tension (HT)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	32,712	$ 353.84	$ 11,574,814	$ 371.68	$ 12,158,396
3	HT Night Service Rider	12,912	$ 11.39	$ 147,068	$ 11.45	$ 147,898
4						
5	**Total Customer Charge Revenue**			$ 11,721,882		$ 12,306,294
6						
7	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	Base Rate	13,682,696,124	$ (0.0006)	$ (8,209,618)	$ (0.0006)	$ (8,209,618)
9						
10	**Total kWh-Based Variable Distribution Revenue**			$ (8,209,618)		$ (8,209,618)
11						
12	**kW-Based Variable Distribution Charges**	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
13	Base Rate	31,355,334	$ 5.49	$ 172,140,784	$ 7.89	$ 247,375,508
14	HT Night Service Rider	316,898	$ 2.44	$ 773,230	$ 3.51	$ 1,112,310
15	High Voltage Discount					
16	33kV	8,550,125	$ (0.18)	$ (1,539,022)	$ (0.26)	$ (2,223,032)
17	66kV	216,780	$ (1.47)	$ (318,667)	$ (2.11)	$ (457,407)
18	>69kV	2,281,209	$ (1.47)	$ (3,353,377)	$ (2.11)	$ (4,813,350)
19						
20	**Total kW-Based Variable Distribution Revenue**			$ 167,702,948		$ 240,994,029
21						
22	Distribution System Improvement Charge (DSIC)			$ 7,534,987		$ -
23						
24	**Total Variable Distribution Charge Revenue**			$ 167,028,317		$ 232,784,411
25						
26	Regulatory Initiatives			$ 950		$ 950
27	Load Reduction			$ (608,894)		$ (834,876)
28	Annualization			$ 124,325		$ 170,466
29						
30	**Adjusted Total Distribution Revenue**			$ 178,266,580		$ 244,427,245

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Electric Propulsion (EP)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	465	$ 1,292.35	$ 600,943	$ 1,292.35	$ 600,943
3	EP Night Service Rider	60	$ 11.39	$ 683	$ 11.45	$ 687
4						
5	**Total Customer Charge Revenue**			$ 601,626		$ 601,630
6						
7	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	Base Rate	444,680,000	$ (0.0006)	$ (266,808)	$ (0.0006)	$ (266,808)
10						
11	**Total kWh-Based Variable Distribution Revenue**			$ (266,808)		$ (266,808)
12						
13	**kW-Based Variable Distribution Charges**	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
14	Base Rate	1,426,020	$ 4.64	$ 6,616,733	$ 6.80	$ 9,696,777
15	EP Night Service Rider	48,281	$ 2.19	$ 105,736	$ 3.21	$ 154,984
16	High Voltage Discount					
17	33kV	17,735	$ (0.18)	$ (3,192)	$ (0.26)	$ (4,611)
18	66kV (for first 10,000 kW of measured demand pe	-	$ (1.47)	$ -	$ (2.15)	$ -
19	>69kV (for first 100,000 kW of measured demand	204,835	$ (1.47)	$ (301,107)	$ (2.15)	$ (440,395)
20						
21	**Total kW-Based Variable Distribution Revenue**			$ 6,418,170		$ 9,406,755
22						
23	Distribution System Improvement Charge (DSIC)			$ 305,601		$ -
24						
25	**Total Variable Distribution Charge Revenue**			$ 6,456,963		$ 9,139,947
26						
27	Regulatory Initiatives			$ -		$ -
28	Load Reduction			$ -		$ -
29	Annualization			$ -		$ -
30						
31	**Adjusted Total Distribution Revenue**			$ 7,058,589		$ 9,741,577

PECO Energy Company (Electric)
Rate Year Ended December 31, 2025
Revised Proof of Revenue at Present and Proposed Rates - Lighting

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer-Owned Lighting**					
2	**Service Location Charges**	**Locations**	**Rate**	**Revenue**	**Rate**	**Revenue**
3	SL-E	2,197,092	$ 6.65	$ 14,610,662	$ 7.65	$ 16,807,754
4	SL-C	127,656	$ 5.63	$ 718,703	$ 6.48	$ 827,211
5	TLCL	105,240	$ 3.67	$ 386,231	$ 4.22	$ 444,113
6	AL	192,384	$ 2.33	$ 448,255	$ 2.68	$ 515,589
7						
8	**Total Service Location Charge Revenue**			$ 16,163,851		$ 18,594,667
9						
10	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
11	SL-E	104,345,923	$ 0.01817	$ 1,895,965	$ 0.02448	$ 2,554,204
12	SL-C	1,984,640	$ 0.03444	$ 68,351	$ 0.04640	$ 92,087
13	TLCL	44,870,617	$ 0.01673	$ 750,685	$ 0.02254	$ 1,011,384
14						
15	**Total kWh-Based Variable Distribution Revenue**			$ 2,715,001		$ 3,657,675
16						
17	**Company-Owned Lighting**					
18	**Component-Based Distribution Charges**			**Revenue**		**Revenue**
19	SL-S			$ 2,260,931		$ 3,045,878
20	POL			$ 2,865,163		$ 3,859,886
21	**Total Component-Based Distribution Revenue**			$ 5,126,094		$ 6,905,764
22						
23	Distribution System Improvement Charge (DSIC)			$ 1,029,380		$ -
24						
25	**Total Distribution Revenue**			$ 25,034,326		$ 29,158,106
26						
27	Regulatory Initiatives			$ -		$ -
28	Load Reduction			$ -		$ -
29	Annualization			$ -		$ -
30						
31	**Adjusted Total Distribution Revenue**			$ 25,034,326		$ 29,158,106

C-Factor Period	Estimated CAP Credits ($)	Estimated R/RH Sales (a) (kWh)	Estimated Shortfall Recovered in Base Rates (b)	Shortfall o/(u) Base Recovery	Shortfall o/(u) Base Recovery (c)
			(3) = (2) * $0.0068 thru 12/31/2024		(5) = (4) * 0.73 thru 12/31/2024
	(1)	(2)	(2) * $0.0102 as of 1/1/2025	(4) = (1) - (3)	(4) * 0.879 as of 1/1/2025
Jan-25					
Feb-25					
Mar-25					
Apr-25					
May-25					
Jun-25					
Jul-25					
Aug-25					
Sep-25					
Oct-25					
Nov-25					
Dec-25					
	$ -	-	$ -	$ -	$ -

Please reference Column (3), Column (5), and Notes (b-c) for PECO's proposed change.

(a) Non-CAP kWh.
(b) Current factor is per settlement approved at Docket No. R-2010-2161575.
PECO is proposing to update these factors effective January 1, 2025.

Projected FPFTY 2025 CAP Bill Credits:	$ 145,200,000
Projected Res Non-CAP Sales for FPFTY 2025 (kWh):	14,258,563,289
Resulting Base Rate Recovery per kWh:	$ 0.0102

(c) Current factor is per settlement approved at Docket No. P-2008-2062739.
PECO is proposing to update this factor effective January 1, 2025 from 73% to 87.9%

E-Factor Period	Total CAP Credits (Shortfall)	Billed R/RH Sales (a) (kWh)	CAP Revenues Recovered in Base Rates (b)	Base Recovery o/(u) Actual	Base Recovery o/(u) Actual (c)	C-Factor Revenue	L-Factor Revenue (d)	L-Expenditures	L - Factor o/(u) Recovery	InPA Revenue (e)	InPA Balance	InPA o/(u) Recovery	Total C, L & F Factor o/(u) Recovery
			(3) = (2) * $0.0068 thru 12/31/2024		(5) = (4) * 0.73 thru 12/31/2024								
	(1)	(2)	(2) * $0.0102 as of 1/1/2025	(4) = (3) - (1)	(4) * 0.879 as of 1/1/2025	(6) = (2) * ($0.00054)	(7) = (2) * $0.00024	(8)	(9) = (7) - (8)	(10) = (2) * ($0.00016)	(11)	(12) = (10) - (11)	(13) = (5) + (6) + (9) + (12)
Jan-24													
Feb-24													
Mar-24													
Apr-24													
May-24													
Jun-24													
Jul-24													
Aug-24													
Sep-24													
Oct-24 (a)													
Nov-24 (a)													
Dec-24 (a)													
	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Please reference Column (3), Column (5), and Notes (b-c) for PECO's proposed change.

(a) Residential Non-CAP Sales.
(b) Current factor is per settlement approved at Docket No. R-2010-2161575.
PECO is proposing to update these factors effective January 1, 2025.

Projected FPFTY 2025 CAP Bill Credits:	$ 145,200,000
Projected Res Non-CAP Sales for FPFTY 2025 (kWh):	14,258,563,289
Resulting Base Rate Recovery per kWh:	$ 0.0102

(c) Current factor is per settlement approved at Docket No. P-2008-2062739.
PECO is proposing to update this factor effective January 1, 2025 from 73% to 87.9%
(d) LIURP Health/Safety and De-facto heating. Per settlements at Docket No. R-2018-3000164 & R-2021-3024601.
(e) InPA Remaining Balance.

Proj CAP-Specific R kWh, 2025	1,027,016
Proj Total R kWh Sales, 2025 (from Exhibit JAB-4)	11,367,080,835
Proj Non-CAP R kWh Sales, 2025	11,366,053,819
Proj CAP-Specific RH kWh, 2025	170,040
Proj Total RH kWh Sales, 2025 (from Exhibit JAB-4)	2,892,679,510
Proj Non-CAP RH kWh Sales, 2025	2,892,509,470
Total Projected Non-CAP Residential kWh Sales, 2025	14,258,563,289

PECO Energy Company, R-2024-3046931 (Electric)

PECO Interrogatories to the Office of Consumer Advocate
Set II

PECO-OCA-II-13. Refer to OCA Statement No. 3, page 22, lines 6-12. Please set forth the factual basis, including all studies, analyses, citations to all Commission precedent, and copies of any supporting documentation, for the assertion that constraining a rate increase to 150% of the system average is "frequently used for the application of gradualism."

Response:

This statement is based on Mr. Johnson's 40 years of experience in cost allocation/rate design proceedings. Furthermore, his experience in Pennsylvania electric rate cases indicates that experts for many different parties propose similar types of 150%, 175%, or 200% of system average moderation limits.

Regarding Commission precedent, *Pa. PUC v. Columbia Gas of Pennsylvania, Inc*., R-2020-3018835 (Order entered Feb. 19, 2021) at 233, for example, states that "[t]he record indicates that although there are no definitive rules for determining what kind of rate increase would violate the principle of gradualism, limiting the maximum average rate increase for any particular class to 1.5 to 2.0 times the system average increase is one common metric that has been used by experts in the Commonwealth." I am not a legal expert with respect to Commission precedent. Therefore, while I have not conducted an exhaustive survey of Pennsylvania Commission precedent regarding common metrics used to assess gradualism in Pennsylvania, the Commission speaks for itself that the 150% cap is considered frequently used for the application of gradualism.

The Order referenced is available at: https://www.puc.pa.gov/pcdocs/1693880.docx

Dated: July 1, 2024

Sponsored by: Clarence Johnson

PECO Energy Company, R-2024-3046931 (Electric)

PECO Interrogatories to the Office of Consumer Advocate
Set II

PECO-OCA-II-15. Refer to OCA Statement No. 3, page 25, lines 12-17.

a. Please provide cost-based justification for the following position: "In my view, when all other classes are receiving a significant rate increase, it is equitable to eliminate revenue decreases and require such classes to bear at least 50% of the system average percent increase. In this case, all classes should share in the burden of paying the overall revenue increase." If a cost-based justification is not applicable, please explain why it is not applicable.

b. Please set forth the factual basis, including all studies, analyses, citations to all Commission precedent, and copies of any supporting documentation, that support implementation of the recommended 50% of system average increase "floor", highlighting all references from each supporting factor to both cost-based evidence and to 50% as the appropriate threshold.

Response:

a. Mr. Johnson's recommendation is a "cost-based" approach warranted in certain cases which involve a proposed overall increase in revenues simultaneous with a revenue reduction for a specific class. The 50% floor guarantees that specified class (lighting) which pay revenues in excess of class cost of service will receive a base revenue increase which is substantially below the system average percent increase. The 50% limit is based on the class' above cost position. The 50% limit also ensures that the class shares in the cost of applying gradualism/moderation to below cost classes.

b. Several factors may be relevant when evaluating a gradualism constraint such as the 50% floor. These factors include: (a) magnitude of the overall increase in revenues; (b) impact on an overall proposal for moderating class revenue changes; and (c) recognizing Bonbright's criteria for a sound rate structure. In Mr. Johnson's experience, public acceptance of a significant rate increase is enhanced if all classes share in the application of rate moderation.

[response continued on next page]

PECO Energy Company, R-2024-3046931 (Electric)

PECO Interrogatories to the Office of Consumer Advocate
Set II

I am not a legal expert with respect to Commission precedent. Therefore, I have not conducted an exhaustive survey of Pennsylvania Commission precedent which may support constraints on class revenue decreases. However, the following proceeding asserts that a class should not experience a revenue decrease when other classes experience a revenue increase:

Pa. PUC v. PECO Energy Company - Gas Division, Docket No. R-2020-3018929 (Order entered June 22, 2021). https://www.puc.pa.gov/pcdocs/1708475.docx

Dated: July 1, 2024

Sponsored by: Clarence Johnson

RESPONSES OF
SOUTHEASTERN PENNSYLVANIA TRANSPORTATION AUTHORITY
TO INTERROGATORIES AND
REQUESTS FOR PRODUCTION OF DOCUMENTS
TO PECO ENERGY COMPANY, SET II

Docket No. R-2024-3046931

PECO-SEPTA-II-1. Refer to SEPTA Statement No. 1, page 9, lines 3-4. Please explain how Mr. Crist's proposal that the rate increase for Rate HT and Rate EP should be limited to the overall increase granted by the Commission is cost-based.

RESPONSE:

Mr. Crist's testimony challenges several aspects of the requested rate increase. Consideration of the magnitude and distribution of the requested increase are considerations the Commission must make.

Provided By: James Crist

PECO ENERGY COMPANY
STATEMENT NO. 7-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

SURREBUTTAL TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECT: RESPONDING TO OPPOSING PARTIES' TESTIMONY REGARDING SCALEBACK OF RATES

DATED: AUGUST 2, 2024

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I. INTRODUCTION AND PURPOSE 1

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SURREBUTTAL TESTIMONY
OF
JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Joseph A. Bisti. I am employed by PECO Energy Company ("PECO" or the "Company") as a Manager of Rate Analysts. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct and rebuttal testimony on behalf of the Company, which are designated as PECO Statement Nos. 7 and 7-R, respectively.

3. Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address a recommendation made by National Railroad Passenger Corporation ("Amtrak") witness Aliea A. Munger, Ph.D. concerning scaling back PECO's proposed class rate increases if the Pennsylvania Public Utility Commission ("Commission") grants less than the Company's requested revenue increase.

II. SCALE BACK OF RATES

4. Q. Please summarize Dr. Munger's concerns with the targeted scale-back methodology proposed by the Bureau of Investigation and Enforcement ("I&E") and Amtrak's alternative recommendation.

A. Dr. Munger opposes I&E witness Esyan Sakaya's scaleback approach that excludes the Electric Propulsion rate class ("Rate EP") because Mr. Sakaya's proposal would retain PECO's proposed 39.2% increase for Rate EP consisting of only two customers (Amtrak and the Southeastern Pennsylvania Transportation Authority). Dr. Munger recommends that the Commission limit revenue and rate increases for all classes, including Rate EP, to no more than 10% higher than the overall system average increase ultimately granted to PECO. She also claims that various proposals for revenue and rate increases to Rate EP – including the Company's original proposal – violates principles of "gradualism, avoidance of rate shock, and inter-class equity."

5. Q. Do you agree that gradualism, avoidance of rate shock and equity should be the primary ratemaking principles employed by the Commission in this case as Dr. Munger suggests?

A. No. Dr. Munger's recommendation is antithetical to cost causation principles. Equity considerations, along with gradualism and others, are certainly valid concerns in balanced ratemaking and are treated as such in the Company's recommended rate design as well as its recommended proportional scaleback methodology. However, cost of service should not be excluded from consideration in any ratemaking or scaleback methodology, even if equity

principles are also reflected in scaleback proposals to ensure that all classes receive a reasonable portion of any Commission-authorized revenue increase.

I note that Ms. Munger does not oppose the Company's proposed EP revenue and rate increases, despite accusing the Company's proposal of violating them. This is evidenced by her use of the Company's original proposal as the basis for her flawed recommendation to cap any class revenue increase to 10% higher than the overall system average increase. In addition, as explained in my rebuttal testimony, PECO's proposed Rate EP increase is within the range of gradualism (1.5 to 2.0 times the system average increase) previously accepted by the Commission.

I also reiterate that Office of Small Business Advocate ("OSBA") witness Kevin C. Higgins (OSBA St. No. 1, p. 11), Office of Consumer Advocate ("OCA") witness Clarence D. Johnson (OCA St. No. 3, p. 23) and Philadelphia Area Industrial Energy Users Group ("PAIEUG") witness Billie S. LaConte (PAIEUG St. No. 1, p. 16) have joined PECO in supporting a proportional scaleback methodology relative to the approved increase.

III. CONCLUSION

6. Q. Does this complete your surrebuttal testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046931**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Joseph A. Bisti, hereby state that I am a Manager of Rate Analysts for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 7
- PECO Exhibit JAB-1
- PECO Exhibit JAB-2
- PECO Exhibit JAB-3
- PECO Exhibit JAB-4
- PECO Exhibit JAB-5

- PECO Statement No. 7-R
- PECO Exhibit JAB-1 Revised
- PECO Exhibit JAB-2 Revised
- PECO Exhibit JAB-3 Revised
- PECO Exhibit JAB-4 Revised
- PECO Exhibit JAB-5 Revised
- PECO Exhibit JAB-6
- PECO Exhibit JAB-7
- PECO Exhibit JAB-8

- PECO Statement No. 7-SR

Dated: August 5, 2024

Joseph A Bisti

Joseph A Bisti

PECO Statement No. 8:

Direct Testimony of
Megan A. McDevitt

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-2024-3046931

DIRECT TESTIMONY

WITNESS: MEGAN A. MCDEVITT

SUBJECT: PROPOSED SURCHARGE CREDITS TO CUSTOMERS IN 2025 AND PROPOSED CHANGES TO PECO ENERGY COMPANY'S ELECTRIC DIVISION TARIFF

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
MEGAN A. MCDEVITT

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

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

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Manager, 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 and professional experience.

A. I earned a Bachelor of Science Degree in Accounting from DeSales University. In 2006, I became a Certified Public Accountant in Pennsylvania. In March of 2022, I was promoted to my current position in PECO's Regulatory Policy and Strategy department, following roles of increasing responsibility within Accounting, Finance, Energy Acquisition, and Gas Supply and Transportation since joining PECO in September of 2004.

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

A. My testimony will address proposed changes to PECO's Tariff Electric-Pa. P.U.C. No. 7 ("Tariff No. 7") that have been incorporated in the Company's proposed Tariff Electric-Pa. P.U.C. No. 8 ("Electric Tariff No. 8") filed in this case. My testimony is divided into several parts. First, I will explain PECO's proposed Fiber Affiliate Revenue Surcharge ("FARS") and Incremental COVID-19 Uncollectible Surcharge ("ICUS"), which will provide rate credits to customers in 2025 for (1) amounts PECO received for past use of its fiber network and (2) the amount of PECO's regulatory asset for incremental COVID-19-related uncollectible expense (the "COVID-19 Regulatory Asset") that is reflected in PECO's current rates. These rate credits total approximately $64 million and are described by Company witness Michael J. Trzaska in PECO Statement No. 3. The changes to Tariff No. 7 consist of revisions to: (1) terms and definitions; (2) rate schedules; (3) riders; (4) existing Section 1307 surcharge mechanisms; and (5) various miscellaneous provisions.

5. Q. Are you sponsoring any exhibits in this case?

A. No. However, as explained by Company witness Joseph A. Bisti in PECO Statement No. 7, the various tariff changes that I am identifying and explaining are reflected in blacklining of the relevant pages of the Company's proposed Electric Tariff No. 8 that Mr. Bisti is sponsoring as PECO Exhibit JAB-2. Accordingly, I will refer to PECO Exhibit JAB-2 in certain points in my testimony.

II. PECO'S PROPOSED SURCHARGE CREDITS FOR 2025

6. Q. Why is PECO proposing rate credits in 2025 in this case?

A. PECO is proposing two new reconcilable surcharge mechanisms – the FARS and ICUS – to expeditiously refund to customers (1) fiber network fees the Company collected from its former affiliate Exelon Generation Company, LLC and Exelon Business Service Company in November 2021 and (2) amounts of incremental COVID-19-related uncollectible expense embedded in PECO's current rates. These amounts will be credited to customers during the one-year period of 2025. In PECO Statement No. 3, Mr. Trzaska discusses the Company's proposed one-time credits in more detail and describes the revenue requirement effect of the amounts that will be refunded to customers in 2025.

7. Q. Please describe PECO's proposed new surcharges.

A. The FARS and ICUS are reconcilable Section 1307 adjustment clauses that will function similarly. Both surcharges will be computed annually.

The FARS and ICUS will reflect the reduction in required revenues in 2025 arising from the fiber network fees and the COVID-19 Regulatory Asset (approximately $16 million and $48 million, respectively). PECO will allocate the $16 million credit for the fiber network fees to each customer class using the "Total Electric Plant In Service" allocators employed in PECO's cost-of-service study ("COSS") prepared by Company witness Tamara J. Jamison for the fully projected future test year ("FPFTY") (Exhibit TJJ-2, Page 26, Line 109). Similarly, PECO will allocate the $48 million credit for the COVID-19 Regulatory Asset to each customer class using the uncollectible "Account 904"

allocators from PECO's COSS presented in PECO's 2021 electric rate case (Exhibit TJJ-2, Page 28, Line 207). Then, for both surcharges, PECO will calculate 2025 rates by dividing the portions allocated to each class by that class's projected FPFTY sales. The reduction in required revenues will be divided by the estimated annual applicable base revenues that will be applied to customers' bills for service rendered during the twelve months ending December 31, 2025. The difference between the allocated and actual reductions in required revenues by class will be subject to refund or recovery in each surcharge's respective annual reconciliation. For any over/under credit balance that remains after the 2025 refund period the Company may propose additional FARS and ICUS 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 FARS and ICUS credits and reconciliation will be subject to audit by the Commission's Bureau of Audits. The FARS and ICUS have been included in the Company's proposed Electric Tariff No. 8 (see Exhibit JAB-2) and references to the application of the FARS and ICUS have been included in the rate schedules to which they are proposed to apply.

III. PROPOSED CHANGES TO EXISTING TERMS AND DEFINITIONS

8. Q. Please describe the revisions that PECO is proposing to the definition of "Holidays."

A. PECO proposes to revise the definition of Holidays to include the new Federal holiday of Juneteenth.

IV. RATE SCHEDULES

9. Q. Please describe the revision PECO is proposing to Rate Schedule GS – General Service ("Rate GS").

A. The current availability provision of Rate GS states that service is provided to customers through a single metering installation. PECO proposes a revision to clarify that PECO does have some unmetered Rate GS accounts, including electronic billboards and bus shelters. This clarification is consistent with PECO's current practice. Per Section 14.6 of the Rules and Regulations, Estimated Usage, the customer's usage and billing demand 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.

V. REVISIONS TO TARIFF RIDERS

10. Q. Is PECO proposing revisions to any existing tariff riders that you will address?

A. Yes. I will address proposed revisions to PECO's Electric Vehicle DCFC Pilot Rider ("EV-FC Pilot Rider") and Economic Development Rider.

11. Q. What is the EV-FC Pilot Rider?

A. The EV-FC Pilot Rider is a pilot program designed to support transportation electrification by encouraging the build out of publicly available (or workplace fleet) fast charging through reduced demand charges. Under the EV-FC Pilot Rider, PECO applies a demand (kilowatts or "kW") credit initially equal to 50% of a Direct Current Fast Charger's ("DCFC's") nameplate capacity rate for customers installing a qualifying public DCFC served under Rates GS, PD, or HT. The demand credit is available for a 36-month term or until the pilot concludes on December 31, 2025, whichever comes first.

12. Q. Is PECO proposing any changes to the EV-FC Pilot Rider?

A. Yes. As described in more detail in the testimony of Company witness Steven DeMott (PECO Statement No. 9), PECO proposes to extend the EV-FC Pilot Rider by five years through December 31, 2030, and proposes tariff changes that will become effective on January 1, 2026, related to the EV-FC Pilot Rider's eligibility criteria, minimum demand requirements, and the calculation of the demand credit.[1]

13. Q. What is PECO's Economic Development Rider ("EDR")?

A. The EDR provides for discounts in the Variable Distribution Charge ("VDC") 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 distribution service and a sustained increase in load and an increase in employment as detailed in the terms of the EDR.

[1] EV-FC Pilot Rider-related changes to the Company's Night Service Rider will become effective on January 1, 2025.

14. Q. Please describe the revisions PECO is proposing to the EDR.

A. To support and encourage growth in all sectors of PECO's industrial and commercial customer group, and based on experience gained from applying the EDR, PECO is proposing to expand the availability of the EDR for both new and existing customers. First, new or existing customers who add an additional 100 megawatts or more of new load and at least 10 new jobs in PECO's service area will now qualify for the EDR.

Second, PECO is proposing to expand the scope of the EDR so that it will be available to new or existing customers who add hydrogen production capabilities to their facilities. A credit equivalent to 15% will only apply to the portion of the customer's VDC related to the hydrogen production equipment nameplate capacity. These enhancements, which provide additional opportunities for customers to qualify for the EDR, will incentivize the innovation of hydrogen production and encourage job creation and load growth within PECO's service area.

15. Q. What is the Capacity Reservation Rider ("CRR")?

A. The 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 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 CRR set forth in the Company's tariff was the product of the settlement of PECO's 2015 base rate case (Docket No. R-2015-2468981). 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. In the settlement of its 2018 electric base rate case at Docket R-2018-3000164 ("2018 Settlement"), the Company agreed to collect data regarding each CRR customer added (class, usage, billing details, and revenue) and the cost of the capacity being reserved, including the basis for determining the cost as either a system average or specific costs to serve each customer.

16. Q. Is PECO proposing any changes to the CRR in this case?

A. No. At this time, PECO has no customers with generation operating in parallel with the Company's distribution system being served under the CRR. While PECO is not proposing any changes to its existing CRR at this time, the Company will continue to analyze the usage and billing data and the cost of capacity reserved for any customers served under the CRR and provide such data in its next electric base rate proceeding.

VI. SECTION 1307 SURCHARGE MECHANISMS

17. 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.

18. Q. You have described the two new Section 1307 surcharges PECO is proposing in this proceeding to provide credits to customers associated with PECO's COVID-19 regulatory asset and fiber network fees. Is PECO proposing changes to any of its existing Section 1307 surcharge mechanisms?

A. Yes, the Company is proposing to revise its Universal Service Fund Charge ("USFC"), Distribution System Improvement Charge ("DSIC") and the Consumer Education Charge ("CEC").

19. Q. Please describe the changes PECO is proposing to the USFC.

A. The USFC, among other things, is a mechanism by which the Company reflects the aggregate bill credits (in dollars) provided to low-income customers through PECO's electric Customer Assistance Program ("CAP") each year that are not included in base rates (the "CAP shortfall"). The current USFC is adjusted so that residential customers pay 73% of the total CAP shortfall amount. The remaining 27% of the CAP shortfall is absorbed by PECO to account for the estimated impact to uncollectible expense and cash working capital arising from incremental changes to the level of CAP bill credits reflected in base rates.

In this proceeding, as explained by Company witness Jacqueline F. Golden in PECO Statement No. 10, the Company is proposing to increase the aggregate value of bill credits provided to electric CAP customers included in its base rates and to change the offset factor applied to reconcilable CAP costs in the USFC

formula from 27% to 10.5%. To implement this change to the offset factor, the electric USFC must be revised.

20. Q. Please describe the revision that PECO is proposing to its DSIC in conjunction with this electric distribution rate case.

A. In accordance with the "New Base Rate" section of PECO's DSIC, which was approved by the Commission's Order entered on October 22, 2015 at Docket No. P-2015-2471423, PECO is required to reset the DSIC to 0% upon the effective date of Commission-approved base rates. Accordingly, the DSIC will be set to 0%, effective January 1, 2025, as shown in PECO Exhibit JAB-2.

21. Q. Please describe the updates PECO is proposing to the CEC.

A. PECO is proposing to revise the CEC formula to remove the "S factor," which represents the cost of implementing the supplier-oriented bill (as approved in Docket M-2014-2401345) and is no longer applicable. PECO is also proposing several revisions to remove obsolete language that refers to "the coming transition to a competitive market" in the CEC. The Company is also proposing to replace the term "procurement class" with "customer class" to ensure consistency with other sections of the Electric Service Tariff.

Finally, PECO is proposing to revise the CEC to include costs associated with additional education and outreach directed to low- and moderate-income customers about PECO's universal service programs described by Ms. Golden. Commencing on January 1, 2025, PECO proposes to recover up to $800,000 per year in incremental costs associated with this expanded outreach proposal through the CEC.

22. Q. Are there any other matters related to Section 1307 mechanisms in PECO's Electric Service Tariff that you wish to address?

A. Yes, I would like to address PECO's Tax Accounting Repair Credit ("TARC") and Federal Tax Adjustment Credit ("FTAC").

The TARC is a rate adjustment mechanism that became effective January 1, 2013 pursuant to the terms of the Joint Petition for Settlement of Rate Investigation in the Company's 2010 electric rate case at Docket No. R-2010-2161575 ("2010 Settlement"). As I will explain, PECO has fully complied with the terms of the 2010 Settlement pertaining to the TARC, where PECO committed to take several actions if PECO subsequently decided to change its method of tax accounting so that property-related expenditures PECO capitalizes for book purposes may be treated for income tax purposes as repair expenses that are deductible in the year incurred.

In particular, PECO agreed to notify the Commission if it elected to make such a change and to pass-through to customers, by a seven-year amortization, the revenue requirement effect of a retrospective, one-time "catch-up" deduction permitted under Section 481(a) of the Internal Revenue Code when a tax accounting change like the "repairs" election is made. Following the 2010 Settlement, PECO changed its method of tax accounting to expense electric utility "repair" costs for income tax purposes. Therefore, consistent with the terms of the 2010 Settlement, PECO notified the Commission of its decision and established the TARC to provide bill credits designed to return $177,882,711 of

tax benefits attributable to the "catch-up" repair deduction to customers over the seven-year period from January 1, 2012 through December 31, 2018.

The total tax benefit of the "catch-up" deduction was returned to customers one year earlier than anticipated, but this action resulted in a small over-recovery balance of about $62,000 as of December 31, 2022. Approximately $36,000 of the over-recovery was owed to the residential customer class and was returned through the TARC. About $26,000 of the over-recovery is owed to the commercial customer class. As explained by Mr. Trzaska in PECO Statement No. 3, the Company proposes to return this small over-recovery balance to commercial customers through a distribution revenue requirement reduction. Accordingly, the Company has fully satisfied the requirement of the 2010 Settlement regarding the TARC.

PECO is also proposing to remove references in Electric Tariff No. 8 to the FTAC and TARC because those mechanisms are no longer part of PECO's electric service tariff.

23. Q. Has PECO fully complied with the terms of the 2018 Settlement regarding the FTAC?

A. Yes. The FTAC is a rate adjustment mechanism to refund the 2018 estimated Tax Cuts and Jobs Act ("TCJA") savings to customers. Under the 2018 Settlement, the FTAC for residential, small commercial and streetlighting customers was established to refund the TCJA savings over the one-month period of January 2019, subject to reconciliation, while the FTAC for large commercial and

industrial customers was established to refund the TCJA savings over the one-year period of 2019.

During 2019 and 2020, PECO made several additional FTAC filings to continue to reconcile the final balances for residential, small commercial, streetlighting and large commercial and industrial customers, eventually resetting the FTAC to 0% for all rate classes effective January 1, 2021. The remaining balance as of December 31, 2022, is a credit of $23,464. As explained by Mr. Trzaska, PECO proposes to return the small over-recovery balance to customers through a distribution revenue requirement reduction. Accordingly, the Company has fully satisfied the requirement of the 2018 Settlement regarding the FTAC.

VII. MISCELLANEOUS

24. Q. What are the miscellaneous revisions that are being proposed by PECO and reflected in Electric Tariff No. 8?

A. PECO is proposing four miscellaneous revisions:

First, PECO is proposing to revise the formula in the USFC to remove the "F" Correction Factor of the In-Program Arrearage Forgiveness Program ("F-Factor"), which was a result of the Settlement at Docket R-2015-2468981. PECO has not included the F-Factor in its USFC rate calculations since 2018 and as of 2023, PECO is refunding any over-collected balances to customers through the USFC. PECO is also proposing to revise the "L" Factor to remove the De Facto Heating Pilot that ended on December 31, 2023. Also, for consistency with its

Gas Service Tariff, PECO is proposing to revise the "I" Factor to add the statement "The interest calculation will not apply to LIURP amounts."

Second, PECO is proposing to revise the Availability/Applicability section of the Economic Development Rider to remove the reference to provision IC, which does not exist in the subsequent Employment & Load Growth section.

Third, PECO is proposing to revise the List of Communities Served section in order to correctly reflect Narberth Borough and Lower Merion Township as Montgomery County. The Township of Whitemarsh was also incorrectly categorized as a First-Class Township.

Finally, PECO is proposing to correct a misstatement in the Minimum Charge language in Rate GS. The first sentence should read "The monthly minimum charge for customers without demand measurement will be the Fixed Distribution Service Charge, plus the Variable Distribution Service Charge per kW of minimum billing demand as described above."

VIII. CONCLUSION

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

A. Yes, it does.

PECO ENERGY COMPANY
STATEMENT NO. 8-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

REBUTTAL TESTIMONY

WITNESS: MEGAN A. MCDEVITT

SUBJECT: SURCHARGE CREDITS TO CUSTOMERS IN 2025

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
MEGAN A. MCDEVITT

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Megan A. McDevitt. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Manager, Retail Rates. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct testimony marked as PECO Statement No. 8. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to Bureau of Investigation and Enforcement ("I&E") witness Christine Wilson regarding PECO's proposed Fiber Affiliate Revenue Surcharge ("FARS") and Incremental COVID-19 Uncollectible Surcharge ("ICUS"), which will provide rate credits totaling approximately $64 million to customers in 2025 for (1) amounts PECO received for past use of its fiber network and (2) the amount of PECO's regulatory asset for incremental COVID-19 related uncollectible expense (the "COVID-19 Regulatory Asset") that was recovered through PECO's current rates.

II. PECO'S PROPOSED SURCHARGE CREDITS FOR 2025

4. Q. Have you reviewed the portion of I&E witness Wilson's direct testimony that discusses PECO's proposed new surcharges and rate credits?

A. Yes. Ms. Wilson recommends that PECO amortize the rate credits over three years as a reduction to revenue requirement in this case, instead of refunding the amounts through a surcharge over a one-year period in 2025, to avoid imposing an additional burden on the Commission's Bureau of Audits to evaluate the final FARS and ICUS reconciliation statement.

5. Q. Do you agree with Ms. Wilson's recommendation?

A. No. PECO's proposed new surcharges will expeditiously refund to customers (1) fiber network fees the Company collected from its former affiliate Exelon Generation Company, LLC and Exelon Business Service Company in November 2021 and (2) the COVID-19 Regulatory Asset. PECO anticipates that the proposed ICUS and FARS will only be in effect for two years, and the Bureau of Audits will only need to review one annual reconciliation filing per surcharge after the 2025 refunds, and, if needed, the final reconciliation statements. PECO will address any remaining over/undercollection balances after 2026 through a revenue requirement adjustment in its next electric base rate case. Moreover, PECO is eliminating two of its existing surcharges in this case – the Tax Accounting Repair Credit and Federal Tax Adjustment Credit – and therefore PECO's approach of providing the rate credits through surcharges instead of base rates will not create incremental administrative burden on the Bureau of Audits.

III. CONCLUSION

6. Q. Does this complete your rebuttal testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046931**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Megan A. McDevitt, hereby state that I am the Senior Manager, Retail Rates for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 8
- PECO Statement No. 8-R

Dated: August 5, 2024

Megan A. McDevitt

PECO Statement No. 9:

Direct Testimony of
Steven J. DeMott

PECO ENERGY COMPANY
STATEMENT NO. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

DIRECT TESTIMONY

WITNESS: STEVEN J. DEMOTT

SUBJECTS: ELECTRIC VEHICLE CHARGING PILOT AND ELECTRIC VEHICLE FAST CHARGING PILOT RIDER

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
STEVEN J. DEMOTT

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Steven J. DeMott. My business address is PECO Energy Company ("PECO" or the "Company"), 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO as Senior Manager of Strategic Planning. In that capacity, I am responsible for managing and directing activities necessary to support executive leadership and business stakeholders with developing strategic business initiatives that will provide value for our customers.

3. Q. Please describe your educational background.

A. I have a Bachelor of Science in Economics from the University of Pennsylvania Wharton School of Business and a Master of Business Administration from the University of Pittsburgh Katz Graduate School of Business.

4. Q. Please describe your professional experience.

A. I began my career with PECO in 1999 as a senior financial analyst. Between 2002 and 2014, I held management roles in several departments in the areas of marketing, revenue management, and eChannels (digital customer service).

In July 2014, I was promoted to senior manager of customer projects and system support where I led a team of professionals in developing analytical and

technology strategy for PECO customer operations while providing project management, change management/business integration, and application maintenance support for all customer service technology platforms.

In December 2019, I became Senior Manager of Strategic Planning for PECO and am now responsible for working closely with our organization and stakeholders to lead strategic planning, opportunity assessments, and the development and execution of strategic initiatives that will provide value to our customers.

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

A. The purpose of my testimony is to describe: (1) PECO's proposal to extend its pilot incentive programs for electric vehicle ("EV") charging (the "EV Charging Pilot") and (2) PECO's proposal to extend and modify its Electric Vehicle Fast Charging Pilot Rider (the "EV-FC Rider"). The following chart summarizes these changes.

	Subject	**Current state**	**Proposed change**
EV Charging Pilot	Duration	Ends 12/31/2024	Extend through 12/31/2029
	Budget	$1,625,000 over three years	$1,000,000 per year
	L2 Program rebate amount	Percentage of actual make-ready costs with per-port caps	Fixed rebate amounts per-port
	Rebate limits per customer	L2 Program limit of 20 ports; overall limit of $60,000 ($500,000 for transit authorities)	Annual limit of $60,000 ($200,000 for transit authorities)
	Data requirement	Applies only to chargers receiving rebates	Applies to all chargers at the site

	Subject	Current state	Proposed change
EV-FC Rider	Duration	Expires 12/31/2025	Extend through 12/31/2030
	Definition	"high-powered" DCFC is undefined	Add definition for "high-powered"
	Meter Eligibility	No metering requirement, but DCFC must be "publicly available"	Require DCFCs to be separately metered, no requirement that DCFC be "publicly available"
	Demand Credit	50% of nameplate charging capacity	20% of measured demand
	Minimum demand	Rules of customer's applicable base rate apply; typically, 40% of contract maximum demand	30% of contract maximum demand or 15 kilowatts if there is no contract maximum
	Other riders	Not addressed	Address interaction with Night Service Riders and ineligibility for Economic Development Rider

6. Q. Are you sponsoring any exhibits to accompany your direct testimony?

A. Yes, I am sponsoring Exhibit SJD-1, which includes forecast information about EVs and Direct Current Fast Charger ("DCFC") charging stations in PECO's service territory.

II. EV CHARGING PILOT

A. PECO's Existing Pilot

7. Q. Please describe PECO's EV Charging Pilot.

A. The EV Charging Pilot is designed to incentivize the development of EV charging sites in the Company's electric service territory, educate customers about transportation electrification ("TE"), and gather important EV charging data to inform the Company's future distribution system planning and rate design. The EV Charging Pilot was originally established as part of a comprehensive

settlement (the "2021 Settlement") approved by the Pennsylvania Public Utility Commission (the "Commission") in the Company's most recent electric base rate proceeding in 2021.[1] On April 27, 2023, PECO filed a petition requesting Commission approval of certain modifications to the EV Charging Pilot, including replacing the Transit Charging Program with the Public Benefit Charging Program (the "Pilot Modification Petition"). On September 21, 2023, the Commission approved PECO's proposed modifications to the EV Charging Pilot.[2] As modified, the EV Charging Pilot has three components: (1) the Commercial and Industrial Level 2 Charging Program (the "L2 Program"); (2) the Public Benefit Charging Program; and (3) the Electric Vehicle Education and Outreach Program.

8. Q. Please describe the EV Charging Pilot's L2 Program.

A. PECO launched the L2 Program in April 2022. The program is designed to address the upfront costs of developing charging sites and help the Company understand the load profile and other implications of commercial and industrial Level 2 ("L2") EV charging. Qualifying customers can receive an L2 Program incentive in exchange for providing detailed information for each participating installed charger over a two-year period, including interval data (kW and kWh) covering charging event duration, site-specific charging load management strategies, and equipment utilization rates. This "real world" data on charging installations will inform future rate design and distribution system planning for the load impacts of TE.

[1] *See* Docket No. R-2021-3024601 (Order entered, Nov. 18, 2021) (the "2021 ERC Proceeding").

[2] *See* Docket No. P-2023-3040238 (Order entered Sept. 21, 2023) (the "Pilot Modification Order").

The incentive level varies depending upon the location of the charging site as follows:

- The lesser of $3,000 per charging port or 75% of make ready costs incurred for sites in an Environmental Justice Area ("EJA") (as designated by the Pennsylvania Department of Environmental Protection ("PA DEP") at the time of application) within PECO's electric service territory.

- The lesser of $2,000 per charging port or 50% of make ready costs incurred for sites at any other location within PECO's electric service territory.

The L2 Program is subject to the following requirements and limitations:

- The incentives are available to all applicable classes of commercial and industrial customers (for example, Rates GS, HT, and PD) for applications including, but not limited to, public charging, fleet charging, bus charging, multi-unit dwelling charging, and workplace charging.

- Each customer is eligible to receive the make-ready incentive for a maximum of 20 ports over the duration of the Pilot.

- Incentives are paid on a first-come first-served basis upon placement of the charging station(s) into service during the years 2022 through 2024.

- If a customer site receives a governmental grant or tax incentive toward the construction of and equipment purchases for a charging station, the incentive from PECO shall not exceed the total cost of equipment, installation, and make ready less the value of the governmental grant or tax incentive.

9. Q. Please describe the EV Charging Pilot's Public Benefit Charging Program.

A. PECO launched the Public Benefit Charging Program in October 2023. Similar to the L2 Program, the Public Benefit Charging Program is designed to address the upfront costs of developing charging sites and to help the Company understand the load profile and other implications of commercial and industrial EV charging. However, this program is more focused on public transportation, the non-profit sector, and local government.

Incentives are available for qualifying customer-owned L2 or fast charging equipment that is connected to a PECO meter on a non-residential account that meets at least one of the following criteria and will be used to charge EVs that are operated predominantly within the PECO electric service territory:

- charging stations dedicated primarily to battery electric passenger buses, commuter shuttles, vehicles devoted to providing shared ride/demand response services for paratransit, medical assistance, persons with disabilities, or senior citizens, school buses, taxicabs, and/or rideshare vehicles;
- charging stations dedicated primarily to vehicles owned or operated by one or more 501(c)(3) organizations;
- charging stations owned by or dedicated primarily to vehicles owned or operated by county, municipal, or regional government entities; and
- charging stations available to the general public, utilizing a non-proprietary charging standard and located in an EJA as designated by PA DEP at the time of application.

Customers receiving incentives agree to facilitate PECO's collection of data from participating chargers for two years, with one exception; if fast chargers are installed by a transit authority, PECO will collect the data for three years.

Public Benefit Charging Program incentives are capped at 50% of the cost of equipment, installation, and make ready work for the project, and consideration is given to any applicable governmental grants or tax credits.

Transit authorities installing fast chargers with a capacity of at least 250 kW per charging port are subject to a maximum incentive of $500,000 per project site. All other eligible customers are subject to a maximum incentive of $60,000 over the duration of the Pilot, inclusive of incentives paid through both the L2 Program and the Public Benefit Charging Program.

10. Q. Please describe the EV Charging Pilot's Electric Vehicle Education and Outreach Program.

A. PECO conducts proactive EV education and outreach to increase customer knowledge of the Company's EV offerings including the EV Toolkit, the EV-FC Rider, the EV registration incentive, the L2 Program, and the Public Benefit Charging Program. The awareness campaign utilizes a variety of communication channels including, but not limited to, bill inserts, email, social media, website updates, and printed materials.

11. Q. Does PECO engage with stakeholders about TE and the implementation of the EV Charging Pilot?

A. Yes. Consistent with the 2021 Settlement, PECO convenes a collaborative working group meeting[3] at least twice annually to discuss opportunities to support the equitable expansion of TE within PECO's service territory. Topics for discussion include: outreach and education efforts, the provision of TE programming to low income communities and other historically disadvantaged communities, and potential local impacts of electric vehicle infrastructure investment.

Based on availability, PECO will provide aggregated kWh consumption of chargers supported by the program and aggregated load profile information for participating L2 chargers at stakeholder collaboratives and will post that information to its website within ten business days after the stakeholder collaborative.

[3] The enrollment form for the collaborative working group meetings and information from past proceedings are available at this link: https://www.peco.com/DoingBusinessWithUs/Pages/TransportationElectrification.aspx.

The Company further committed to brief the parties to the 2021 ERC Proceeding prior to making a filing to modify or extend the EV Charging Pilot, provide appropriate data support for Pilot incentives, and if publicly available: (1) include an EV forecast for the future pilot period; and (2) provide data showing the public and private charging that is coming online in PECO's service territory.[4] PECO conducted the prefiling briefing on March 27, 2024 during which it shared the information in PECO Exhibit SJD-1 and informed the parties of the Delaware Valley Regional Planning Commission's map-based EV forecast tool.[5]

PECO also committed that any filing to modify or extend the EV Charging Pilot will include data showing a basis for the incentives and identify the data sources and evaluation techniques used. This testimony addresses those commitments.

12. Q. What are the reporting requirements for the EV Charging Pilot?

A. Pursuant to the 2021 Settlement and the Pilot Modification Order, PECO committed to develop an annual anonymized public report for submission to the Commission regarding the L2 Program and the Public Benefit Charging Program in 2023, 2024, and 2025. The report is to be published by PECO by April 1 of each year and cover the preceding calendar year.[6] Each report will include at least the following information:

a. Number of participating charging ports, by county;

b. Number of participating sites, by county;

[4] As noted earlier, PECO Exhibit SJD-1 includes several EV-related forecasts.

[5] https://www.dvrpc.org/webmaps/electric_vehicles/.

[6] EV Charging Pilot annual reports are available at www.peco.com/doing-business-with-us/stakeholders-collaboratives/transportation-electrification.

c. Aggregate dollar value of incentives provided to participating customers;

d. Aggregate annual kWh consumption of L2 chargers supported by county;

e. Aggregated load profile information for participating L2 chargers;

f. Number of requests received for participation;

g. Initiated requests not funded;

h. Anonymized reasons why initiated requests were not funded; and

i. A description of where charging infrastructure was installed.

13. Q. What is the budget for the EV Charging Pilot?

A. The EV Charging Pilot has a budget of $1,625,000. The budget is allocated as follows:

- $575,000 dedicated to L2 Program incentives and administration;
- $1,000,000 shared between the L2 Program and the Public Benefit Charging Program for incentives and administration; and
- $50,000 for the EV Education and Outreach Program.

Pilot incentives are available for electric vehicle service equipment ("EVSE") installed in calendar years 2022 through 2024, while program administration costs will extend into 2027 for ongoing data collection. PECO currently projects that, by the end of 2024, approximately $1,291,000 will be spent on incentives, $229,000 on program administration, and $50,000 on education and outreach.

14. Q. How many customers have benefitted or are expected to benefit from the EV Charging Pilot in 2022 through 2024?

A. As of February 29, 2024:

- 32 customer accounts have received L2 Program incentives totaling $305,756;
- 39 customer accounts have reserved L2 Program incentives totaling $375,000 for projects currently underway;

- 10 customer accounts have reserved Public Benefit Charging Program incentives totaling $450,950 for projects currently underway; and

- Administrative costs for the EV Charging Pilot were $73,125 in 2022, $56,500 in 2023, and are budgeted as $99,000 in 2024.[7]

15. Q. How is the Company recovering these EV Charging Pilot costs?

A. The Company is recovering the EV Charging Pilot costs over 2022-2024 as follows:

- $575,000 for the L2 Program from Commercial and Industrial ("C&I") customers;

- $1,000,000 for the Public Benefit Charging Program (originally dedicated to the now canceled Transit Charging Program) from Large C&I customers; and

- $50,000 for EV Outreach and Education from all customer classes.

16. Q. In the Pilot Modification Petition, the Company committed, in its next electric distribution base rate case, to make a proposal regarding the treatment of funds initially earmarked for the Transit Charging Program and utilized instead under the expanded L2 Program and the Public Benefit Charging Program. What is the Company's proposal for those funds?

A. The Company is proposing to shift recovery of the $1,000,000 initially earmarked for the Transit Charging Program from Large C&I customers to all C&I customers, in proportion to customer count, in light of the Public Benefit Charging Program and L2 Program being available to all C&I customers. The Company proposes to amortize that shift in allocation over two years, 2025 and 2026. The result will be an annual credit to Large C&I customers and a corresponding annual charge to Small C&I customers of approximately $413,000

[7] Administrative costs have changed year-over-year with the scope of the EV Charging Pilot. 2022 costs included the initial data integration with the program administrator, L2 Program launch, and 9 months of L2 Program operation. 2023 costs included 12 months of L2 Program operation as well as the Public Benefit Charging Program launch and 3 months of Public Benefit Charging Program operation. 2024 costs include 12 months of operation for both the L2 Program and the Public Benefit Charging Program.

as demonstrated in PECO Exhibit TJJ-7, Schedule-16, sponsored by Company witness Tamara J. Jamison in PECO Statement No. 6.

B. PECO's Proposed Pilot Revisions

17. Q. What changes are PECO proposing to the EV Charging Pilot?

A. PECO is proposing to extend the term of the EV Charging Pilot by five years through 2029 (the "Extension Period"), including the stakeholder engagement and reporting requirements, and implement the following changes during the Extension Period:

1) Establish an annual budget of $940,000 as a shared source of funding for the L2 Program and the Public Benefit Charging Program;

2) Establish an annual budget of $60,000 for EV Outreach and Education with $40,000 of that budget to be used to expand the Company's online EV Toolkit to include content and calculators for fleet operators;

3) Replace the L2 Program incentive limit of 20 charging ports per customer and the EV Charging Pilot incentive limits of $500,000 for transit authorities and $60,000 for all other customers with an annual incentive limit per participating customer, inclusive of both the L2 Program and the Public Benefit Charging Program. The annual incentive limit would initially be set at $200,000 for transit authorities and $60,000 for all other customers, but PECO would have the flexibility to adjust the incentive level for non-transit authority customers within the range of $40,000 to $100,000 to reflect actual demand for rebates. PECO would report any such adjustment at the next TE collaborative and in the Company's next annual EV program report to the Commission;

4) Simplify the L2 Program incentives to be $3,000 per charging port for EVSE located in an EJA and $2,000 per charging port for EVSE located anywhere else in the PECO electric service territory; and

5) Expand the requirement for participating customers to provide data from their EVSE to include all EVSE located at the premises for which the incentives are issued and permit PECO, in its sole discretion, to waive this requirement for pre-existing EVSE where requiring data from that pre-existing EVSE would create hardship for the customer.

18. Q. Why does PECO propose to extend the EV Charging Pilot?

A. Advancing TE is a policy priority of both the Biden administration[8] and the Shapiro administration[9] because TE is a critical component in reducing greenhouse gas emissions. The movement toward TE in Pennsylvania is already in progress. The estimated number of plug-in EVs in operation in the PECO service territory has nearly quadrupled from 12,800 at the end of 2020 to approximately 47,500 at the end of 2023. See PECO Exhibit SJD-1, Schedule 1.

A range of forecasts also indicate a very substantial increase in EV penetration in the next several years. For example, PJM forecasts that summer coincident peak EV charging load, and implicitly, the number of EVs in operation, in PECO's service territory will grow fivefold from 2024 to 2027 and tenfold from 2024 by 2030. Assuming that year-over-year growth in 2024 will match the 2023 level, this implies nearly 335,000 EVs in operation by 2027 and more than 685,000 EVs by 2030. This extrapolated PJM forecast represents a faster EV adoption rate than PECO's internal forecast of more than 225,000 EVs in operation by 2027 and more than 590,000 EVs by 2030. For the details of these forecasts, see PECO Exhibit SJD-1, Schedule 3. Schedule 2 of PECO Exhibit SJD-1 displays three EV

[8] *See, e.g.*, Biden-Harris Administration Announces Latest Steps to Deliver a National Network of Convenient, Reliable, Made-in-America Electric Vehicle Chargers, U.S. Department of Transportation, "…President Biden [has] goals for America to lead the world in EV manufacturing and adoption." https://www.transportation.gov/briefing-room/biden-harris-administration-announces-latest-steps-deliver-national-network; FACT SHEET: President Biden's Economic Plan Drives America's Electric Vehicle Manufacturing Boom, The White House, "Since his first day in office, President Biden's auto vision and leadership has positioned the United States to lead the EV future…." https://www.whitehouse.gov/briefing-room/statements-releases/2022/09/14/fact-sheet-president-bidens-economic-plan-drives-americas-electric-vehicle-manufacturing-boom/.

[9] *See, e.g.*, Shapiro Administration, U.S. Senator Casey, Federal Highway Administration, And Labor Partners Announce Federal Electric Vehicle Charging Infrastructure Funding For 54 Projects In 35 Counties, "…National Electric Vehicle Infrastructure (NEVI) funding... awards further the Shapiro Administration's work to address climate change, grow the Commonwealth's economy and ensure that the future of Pennsylvania transportation is on track to be cleaner, safer, more affordable, and more reliable than ever before." www.media.pa.gov/pages/PENNDOT-details.aspx?newsid=806.

adoption scenarios from the Electric Power Research Institute ("EPRI"). The extrapolated PJM forecast and the PECO internal forecast both fall between EPRI's Medium and High adoption scenarios.

The continued growth in EV penetration will likely be driven by several factors, including the $7.5 billion in EV infrastructure grants[10] provided under the Infrastructure Investment and Jobs Act of 2021 and extended tax credit eligibility for EVs[11] provided by the Inflation Reduction Act of 2022. In the private sector, many vehicle manufacturers have announced plans to significantly expand their EV offerings for both passenger and commercial vehicles, and new manufacturers have also been entering the market. S&P Global projects that vehicle manufacturers will offer 200 models of EVs by 2026,[12] up from 40 models in 2023 and 17 models in 2020. As more EVs come to market, a combination of price competition and battery manufacturing advances is putting downward pressure on new EV prices.[13] Further, with the growth in Environmental/Social/Governance investing, many corporate fleet operators, including PECO, have made public commitments to transition some or all of their fleets to EVs.[14]

[10] *See, e.g.*, https://bipartisanpolicy.org/blog/a-status-update-on-ev-charging-infrastructure-investments-in-the-iija/.

[11] *See, e.g.*, https://electrificationcoalition.org/work/federal-ev-policy/inflation-reduction-act/.

[12] https://www.carscoops.com/2023/09/200-ev-models-expected-to-be-on-sale-by-2026-creating-fierce-competition/.

[13] *See, e.g.*, Incentives and lower costs drive electric vehicle adoption in our Annual Energy Outlook, U.S. Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=56480.

[14] *See, e.g.*, How Electric Transportation Is Impacting The Trucking Industry, Forbes, https://www.forbes.com/sites/forbestechcouncil/2023/02/01/how-electric-transportation-is-impacting-the-trucking-industry/?sh=145c46a01fa1.

Supporting TE, including the growth of EVs, can present some implementation challenges for PECO and PECO's customers, including the substantial upfront costs to establish charging stations, the significant load changes on PECO's distribution system arising from increased EV charging activity, and the need to educate customers about the use and benefits of EVs. Sustaining the growth in EV penetration will require that charging infrastructure keep up with or, ideally, stay somewhat ahead of growth in demand to enable EV owners to have a positive experience with their vehicles. Likewise, PECO needs to continue to advance its understanding of EV charging loads in order to adequately plan for and accommodate the rapid growth in charging loads.

Extending the EV Charging Pilot addresses these implementation challenges by partially mitigating the upfront costs of constructing EVSE and by enabling PECO to continue to build a robust data set of EV charging loads, including use cases such as workplace charging and fleet charging that have been underrepresented among applications to date for EV Charging incentives. Additionally, extending the larger incentives offered under the Public Benefit Charging Program will help local governments in our region advance their environmental goals and will support the equitable advancement of TE by improving the business case for constructing EVSE in EJAs.

19. Q. How did PECO determine the proposed budget level for the Extension Period of the EV Charging Pilot?

A. PECO considered the Company's experience to date with the shared $1,000,000 budget for the L2 Program and Public Benefit Charging Program. The application window for that funding opened in October of 2023, and, in the first

five months, PECO received applications for $560,000 in rebates. If that pace was sustained for twelve months, the annual rebate amount requested or applied for would be $1,120,000. PECO anticipates that ongoing annual administrative costs will be in the range of $100,000 to $140,000. Allowing for some projects to fall through, PECO believes that a $1 million annual budget will be appropriate to meet the needs of our customers and will enable the EV Charging Pilot to achieve its goals without unduly burdening nonparticipating customers.

20. Q. Why is PECO proposing to change the EV Charging Pilot incentive limits?

A. PECO's existing incentive limits apply to the total Pilot period (e.g., no more than $60,000 over the term of the Pilot) and were intended to ensure that the limited program budget would be distributed across a large number of customers. Because PECO is proposing a five-year expansion of the Pilot term as well as increased Pilot funding, the Company believes it would be unduly restrictive to apply the current incentive limits to the longer Pilot period.

The Company considered two alternatives to the current limits: (1) establishing an incentive limit at the premises level, as is done in many utility programs;[15] and (2) changing the customer-level incentive limit to be an annual limit. The Company believes that an annual customer-level limit will better achieve the goal of equitably apportioning incentives across our customer base because a premises level limit would enable a single multisite customer to monopolize a significant

[15] For example, Baltimore Gas & Electric (https://www.bge.com/smart-energy/innovation-technology/electric-vehicles/multi-family-property-rebate-program), Delmarva Power (Maryland) (https://www.delmarva.com/smart-energy/innovation-technology/electric-vehicle-program-md/workplace-charger-rebate-program), PEPCO (Maryland) (https://www.pepco.com/smart-energy/innovation-technology/md/electric-vehicle-program/workplace-charger-rebate-program), and PSE&G (https://nj.myaccount.pseg.com/myservicepublic/electricvehicles) commercial EVSE incentives are capped at $30,000 per site, and Atlantic City Electric's commercial EVSE incentives caps range from $9,000 to $120,000 per site (https://www.atlanticcityelectric.com/smart-energy/innovation-technology/public-charger-rebate).

portion of a given year's budget by simultaneously applying for incentives at several premises.

The Company is also proposing to reduce the annual limit for transit authorities from $500,000 to $200,000, beginning in 2025, to enable equitable distribution of the EV Charging Pilot budget across customers. The current $500,000 annual limit in the Public Benefit Charging Program is derived from the per-site limit that existed in the discontinued Transit Charging Program. Going forward, a $200,000 annual limit for transit authorities would be sufficient funding to cover the local match requirement for one federally incentivized enroute charging station each year. In its Zero Emission Bus Playbook,[16] published in April 2022, SEPTA estimates the cost of an enroute charging station as $906,928. The U.S. Department of Transportation's Congestion Mitigation and Air Quality Improvement Program[17] grants, for which enroute transit charging is an eligible application, require a 20% local match. An incentive of $200,000 would therefore be sufficient to cover the local match requirement for one enroute charging station with modest headroom for cost inflation.

The Company chose $60,000 as an annual per-customer limit to be consistent with the $60,000 Public Benefit Charging Program limit that was approved by the Commission in the Pilot Modification Order. PECO is seeking the flexibility to adjust the annual per-customer limits (excluding transit authorities) within the range of $40,000 to $100,000 in order to balance the risks of over and

[16] https://planning.septa.org/wp-content/uploads/2022/04/SEPTA-Forward-ZEB-Playbook-2022.04.01.pdf, p. 101.

[17] https://www.transportation.gov/urban-e-mobility-toolkit/e-mobility-infrastructure-funding-and-financing/federal-funding-programs#.

undersubscription.[18] If demand for Pilot incentives exceeds the annual budget, reducing the per-customer limits will enable the Company to distribute the incentives more broadly across its customer base. If the Pilot is undersubscribed, increasing the per-customer incentive limits will enable the Company to ensure the entire budget is expended by offering a larger benefit to customers undertaking larger electrification projects without adversely impacting other customers. The Company is proposing a $40,000 floor to be consistent with the amount currently available to L2 Program customers not in EJAs, i.e., 20 ports at $2,000 per port, with $100,000 as an upper bound (10% of the annual budget) to ensure that a single customer cannot claim an undue share of the incentive pool.

21. Q. Why does PECO propose to simplify the L2 Program incentives?

A. Over the first two years of the L2 Program, the Company has found that requiring receipts for make-ready costs creates an administrative burden for both the customer and the Company that is large relative to the size of the incentives. In some cases, the approach of limiting incentives to a percentage of make ready costs has also led to customer dissatisfaction as customers have received a smaller incentive than they had anticipated. For incentives awarded in 2022 and 2023, the reported total project cost per charging port ranged from $729 to $32,272 with a median of $11,657 and a mean of $12,847. Since the L2 Program incentives will typically cover significantly less than half of those costs, and in light of the administrative burdens discussed above, PECO believes it is appropriate to provide a flat, per charging port incentive without requiring documentation of

[18] PECO will conduct this evaluation during the fourth quarter of each year, to be effective the following calendar year, on a going forward basis.

actual customer costs.

22. Q. Why does PECO propose to extend the data provision requirement to include all EVSE located at the premises?

A. For the data collected through the EV Charging Pilot to be most useful to PECO, it must be both representative and complete. When PECO aggregates or averages data from many premises, e.g., to analyze load profiles, that data is most likely to reflect typical EV charging behavior if it is representative of the charging behavior at the sites from which it was collected. As customers add new EVSE to premises with pre-existing EVSE, it is likely that the locations of newer EVSE will be either more or less conveniently located for EV drivers, e.g., closer or farther from the facility door. Since drivers are likely to choose to park in the most convenient locations, it is reasonable to anticipate that some chargers at a site will receive more usage than others, and that a sample of chargers energized on a specific date may not be representative of the entire site. Additionally, as technology evolves and the ability of EV batteries to charge faster increases, it is likely that newer chargers will have higher average charging capacities than those installed in prior years. Therefore, PECO needs to collect data from every charger at a premises to have confidence that the data collected is representative of the total charging load. A more robust data set will better inform PECO's distribution system capacity planning efforts.

23. Q. How does PECO propose to recover costs associated with the EV Charging Pilot?

A. The Company is proposing to recover Pilot costs through base distribution rates as demonstrated in PECO Exhibit MJT-1, Schedule D-14, which is sponsored by

Company witness Michael J. Trzaska in PECO Statement No. 3. Twenty thousand dollars ($20,000) of the cost of the EV Education and Outreach would be recovered from all customer classes while the $40,000 of EV Outreach and Education dedicated to calculators for EV fleet operators and the $940,000 for the L2 Program and Public Benefit Charging Program costs would be recovered from C&I customer classes only.

III. ELECTRIC VEHICLE FAST CHARGING PILOT RIDER

24. Q. What is the Electric Vehicle Fast Charging Pilot Rider?

A. The EV-FC Rider is a pilot designed to support TE by encouraging the build out of publicly available (or workplace fleet and public transit) fast charging through reduced demand charges. Under the EV-FC Rider, PECO applies a demand (kW) credit initially equal to 50% of a DCFC's nameplate capacity rate for customers installing a qualifying public DCFC served under Rates GS, PD, or HT. The demand credit is available for a 36-month term or until the pilot concludes on December 31, 2025, 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. The Rider does not waive minimum demand, which is 40% of the maximum contract demand for most DCFC operators, except for customers served under Rate GS with maximum potential demand of 500 kilowatts (kW) or less, for which the minimum demand is 1.2 kW.

The EV-FC Rider was part of a comprehensive settlement approved by the Commission in the Company's 2018 electric base rate proceeding at Docket No. R-201821-3000164 ("2018 Settlement") as a five-year pilot beginning on July 1, 2019, and ending on June 30, 2024. On September 21, 2023, the Commission

approved PECO's request to extend the DCFC Pilot Rider by 18 months through December 31, 2025.[19]

25. Q. What are the reporting requirements for the EV-FC Rider?

A. As part of the 2018 Settlement, PECO agreed to collect the following data for DCFCs connected to the PECO system from pilot participants: the number installed, the number of charging ports, the nameplate capacity (kW), hourly and monthly usage (kWh), and the hourly and monthly demand (kW).

26. Q. How many customer accounts are enrolled in the EV-FC Rider and how many DCFC stations are at those sites?

A. As of February 29, 2024, there are 48 customer accounts enrolled in the EV-FC Rider, and those 48 sites have a total of 282 DCFC stations. All of those sites are publicly available.

27. Q. What is the current state of DCFC build out in PECO's service territory?

A. There are 53 publicly available DCFC charging sites with a total of 308 DCFC stations in the PECO territory, but there are many localities in the Company's territory that do not yet have convenient access to DCFCs. For example, according to the PennDOT National Electric Vehicle Infrastructure ("NEVI") Round 1A Funding Opportunity map,[20] only five of the approximately 100 highway interchanges in the PECO service territory have a NEVI-compliant DCFC site within one mile, and seven additional interchanges have been awarded NEVI projects to date. Likewise, only 39 of the 216 ZIP codes within the region

[19] *See* Docket No. P-2023-3039439 (Order entered Sept. 21, 2023).

[20] https://experience.arcgis.com/experience/6696d9749a124136b9d28a7507f300d5/.

have at least one public DCFC site.

28. Q. How much growth does PECO anticipate in EV-FC Rider enrollment?

A. As shown in PECO Exhibit SJD-1, Schedule 4, the Company anticipates that the number of accounts enrolled in EV-FC Rider will grow to a range of 71 to 206 by 2030. The Company believes that the actual results will likely fall toward the high end of that range given that three of the four forecasts shown in the exhibit land in the range of 192 to 206 accounts.

29. Q. What changes is PECO proposing to the EV-FC Rider?

A. PECO is proposing several changes to the Rider with some changes effective January 1, 2026 and others effective January 1, 2025. The following proposed changes would be effective January 1, 2026:

1) Modify the Availability/Applicability to extend the EV-FC Rider by five years through December 31, 2030, to eliminate the requirement that DCFCs be publicly available, and to limit the applicability to a service that is dedicated exclusively to EV charging and that includes at least one permanently connected DCFC served under Rates GS, PD, or HT installed on or after July 1, 2019.

2) Modify the Definitions to specify that to be high-powered, the DCFC must have a nameplate charging capacity of at least 50 kW per charging port.

3) Modify the Miscellaneous General Provisions to remove the reference to DCFCs that are not separately metered and to remove the requirement for the customer to provide usage and demand data for such DCFCs.

4) Modify the Rate Impact to add an adjustment to the minimum demand calculation, modify the demand credit and delete the sentence referencing the Company's right to reduce the demand credit.

5) Modify the Term of Contract to delete the sentence that references extended participation.

The additional proposed change would be effective January 1, 2025:

1) Modify the Other Riders to specify how the demand credit will be applied to a service that is also served under a Night Service Rider and

specify that the EV-FC Rider will not be applied in conjunction with the Economic Development Rider.

The tariff changes required to implement the revised EV-FC Rider are discussed by Company witness Megan A. McDevitt in PECO Statement No. 8 and shown in PECO Exhibit JAB-2, which is sponsored by Company witness Joseph A. Bisti in PECO Statement No. 7.

30. Q. Why does PECO believe the EV-FC Rider should be extended by five years?

A. The Commission's Proposed Policy Statement for Electric Utility Rate Design for Electric Vehicle Charging[21] makes clear the value of offering ongoing EV-specific tariff options. PECO is proposing a 5-year extension to the Rider, rather than proposing to make the Rider permanent, because this proposal includes substantive modifications to the structure of the EV-FC Rider and the Company believes that it is appropriate to evaluate the effectiveness of those modifications within an extended pilot before making those provisions permanent. Additionally, a 5-year extension aligns with the NEVI program, which offers multiple rounds of funding for DCFC sites to be constructed through 2027. By extending the pilot through 2030, PECO provides NEVI applicants/recipients in our service territory with confidence that the EV-FC Rider provisions will be in force long enough to enable them to receive a full 36 months of benefits.

31. Q. Why does PECO propose reducing minimum demand for most customers enrolled in the EV-FC Rider?

A. PECO reviewed the effectiveness of the EV-FC Rider in late 2023. That review included every bill issued under the Rider from its inception through August

[21] *Electric Utility Rate Design for Electric Vehicle Charging*, Docket No. M-2023-3040755 (Proposed Policy Statement Order entered Nov. 15, 2023).

2023. The review found that only 60% of those bills received any demand charge benefit from the Rider. For the remaining 40% of monthly bills, no demand charge benefit was received because the service account's measured demand was less than its minimum demand. In developing the proposed reduction to minimum demand, the Company adopted a design principal that every service enrolled in the Rider should, ideally, receive some benefit from the Rider. Additionally, PECO believes that services with underutilized DCFCs are likely to be the ones most in need of demand credit. By reducing the minimum demand to 30% of the maximum contract demand, the proposed modification to the Rider will ensure that a greater number of enrolled accounts will receive some benefits from the Rider.

The Company proposes a minimum demand of 15 kW for accounts that do not have a maximum contract demand for consistency with the 30% value described above. The smallest nameplate charging capacity that qualifies for the EV-FC Rider is 50 kW, and 15 kW is 30% of 50 kW.

32. Q. Why does PECO propose modifications to the calculation of the EV-FC Rider's demand credit?

A. In developing this proposal, the Company adopted a design principal that the average benefit per service participating in the EV-FC Rider should remain about the same as it is now (approximately $617 per bill). The design goal was to more equitably distribute the benefits of the Rider, rather than to increase the average benefit per service. Because a greater number of customers are expected to receive a demand charge benefit with the reduced minimum demand of 30%, the Company is proposing to reduce the level of demand credit to achieve a

substantially similar per-bill benefit (approximately $619).

In addition, PECO proposes changing the basis for the demand credit from the combined maximum nameplate capacity rating of the DCFC to the monthly measured demand to improve the administrative efficiency of the Rider. The Company has found that many of the accounts enrolled in the Rider have never achieved a measured demand that approaches the combined maximum nameplate capacity rating of the DCFC. Therefore, under the current structure of the tariff, it is necessary for the Company to periodically adjust the demand credit. The process for calculating and applying that adjustment is manual, and the Company has found that the adjustments are difficult to communicate to customers and can lead to customer dissatisfaction. Moving to a percentage of the measured demand calculation eliminates the need for manual adjustments and lessens step-changes in customer bills that can result from the current adjustment process.

33. Q. Why does PECO propose changes to the eligibility criteria for the EV-FC Rider?

A. The current design of the EV-FC Rider with a demand credit based on the combined maximum nameplate capacity rating for all DCFCs connected to the service was based on a belief that many of the accounts likely to enroll in the Rider would be adding DCFCs to an existing service, e.g., for the building in whose parking lot the DCFCs are installed. PECO would then adjust the credit as necessary to avoid inappropriately extending the credit to pre-existing loads. In practice however, only two of the 48 services to enroll in the EV-FC Rider have been at pre-existing services. This is because in most cases, the service for the DCFCs has been requested by the DCFC operator, rather than the site host, thus

necessitating a separate service. In addition, even in cases where the site host and DCFC operator are the same entity, customers have often expressed a preference for a separate service, usually because the DCFCs operate at a higher voltage than the equipment at the pre-existing premises.

In order to base the demand credit on measured demand, rather than nameplate capacity, and to avoid extending the credit to pre-existing loads, it is necessary to limit eligibility to services that are dedicated to EV charging. PECO's experience to date of having nearly all applications for the EV-FC Rider be for new services gives the Company confidence that this change in eligibility criteria will not unfairly impact customers. This change in eligibility requirements necessitates a corresponding change to the Miscellaneous General Provisions to strike the requirement for customers to provide "hourly and monthly usage (kWh), and the hourly and monthly demand (kW)" for premises at which DCFCs are not separately metered, as all customer accounts enrolled in the Rider will henceforth be separately metered.

Finally, the Company proposes to eliminate the requirement that DCFCs be "publicly available," because the definition of "publicly available" in the EV-FC Rider is so broad as to be inclusive of every DCFC use case of which the Company is aware (e.g., the Rider currently indicates that "publicly available" includes "workplace fleet" and "public transit"). Eliminating this requirement simplifies the tariff and eliminates uncertainty for applicants.

34. Q. If a PECO C&I customer installs a DCFC at a premises with other pre-existing loads, what if any steps can they take in order for their DCFC installation to qualify for the EV-FC Rider?

A. Upon the Commission's approval of this proposal, PECO will deem a customer's desire to make their DCFCs eligible for the EV-FC Rider beyond 2025 to be an extenuating circumstance under Tariff Rule 3.7(5) for which the Company will agree to provide multiple services, if reasonable and feasible, to one customer at a single premises, subject to the customer's payment of the cost of any special installations required for that second service.

35. Q. What options do PECO's C&I customers who install a DCFC at a premises with other loads have to manage demand charges related to EV charging?

A. Customers adding a DCFC to an existing premises have two options to manage the impact the DCFCs have on their demand charges. First, a customer who has the ability to schedule the utilization times for their chargers, e.g., the operator of an EV fleet, may be able to schedule charging at times that are noncoincident with the peak demand of the pre-existing facilities and/or to apply managed charging principals to distribute charging throughout the facility's off-peak period. Second, in cases where the demand from the DCFCs is expected to significantly exceed the demand from the pre-existing facilities, the customer may be able to take advantage of the Company's Night Service Rider that provides a discounted demand charge for services that peak between 8:00 PM and 8:00 AM.[22]

36. Q. Why does PECO propose adding a definition of "high-powered" as having a nameplate charging capacity of at least 50 kW per charging port?

A. This clarification to the tariff is intended to codify the practice that PECO has had in place since the Rider's inception in 2019, at which time DCFCs typically had nameplate capacities in the range of 50 to 150 kW. EV charging technology has

[22] *See* PECO Electric Company Tariff Electric Pa P.U.C. No 7 Original Pages No 88-90 for details.

evolved since 2019 with the introduction of medium speed DC chargers with capacities of 22 kW to 40 kW and of very high speed DCFCs with nameplate capacities up to 400 kW. Although 50 kW DCFCs may no longer be considered high-powered by some industry observers, it is PECO's intent to maintain a 50-kW threshold for eligibility for the Rider.

37. Q. Why does PECO propose to allow up to 20% of the EVSE at an eligible premises to be chargers other than DCFCs?

A. The Company's experience has been that some EVSE sites combine both DCFC and L2 charging, and the Company does not desire to make such sites ineligible for the Rider. However, as the Rider's intent is to support the installation of DCFCs, the Company believes that it would be inappropriate to extend the demand credits to sites at which EVSE are primarily L2. The Company believes that a threshold of at least 80% of EVSE capacity being from DCFCs strikes a reasonable balance of requiring a site to be primarily dedicated to DCFC while accommodating secondary L2 EVSE.

38. Q. Why does PECO propose to allow ancillary loads of up to one percent of the EVSE nameplate capacity?

A. The Company recognizes that EVSE sites may need to incorporate other equipment such as illuminated signage, safety lighting, communication equipment, and load management technologies. Wiring such ancillary equipment to a separate meter from that utilized by the EVSE may cause the customer and the Company to incur additional costs. The Company believes that such ancillary loads will typically be significantly less than one percent of the EVSE nameplate capacity and that allowing such loads up to one percent of the EVSE capacity to

be included in the demand credit calculation is reasonable.

39. Q. Please discuss the Company's proposal to clarify concurrent application of the EVFC Rider and a Night Service rider.[23]

A. In response to a customer inquiry about simultaneous enrollment in the EVFC Rider Pilot and a Night Service Rider, the Company reviewed the tariff and observed that the tariff does not discuss how the demand credit should be applied to the account in this situation., i.e., whether the credit should be applied to the On-Peak or Off-Peak demand. Given that the Night Service riders are intended for night-peaking customers, the Company intends that the demand credit be applied to the Off-Peak demand, and the proposed tariff modification makes this intent clear. As of February 29, 2024, no customers are currently enrolled in both the EVFC Rider and a Night Service Rider.

40. Q. Please discuss the Company's proposal to prohibit concurrent application of the EVFC Rider and the Economic Development Rider.

A. After identifying that the tariff does not address concurrent application of the EVFC Rider and a Night Service Rider, the Company reviewed all other riders to determine whether any other cross-impacts of the EVFC Rider are missing from the tariff. That review resulted in the recognition that, similar to the EVFC Rider Pilot, the Economic Development Rider provides the customer a credit on their variable demand charge. Stacking both a demand credit and a rate credit on a single account would be inconsistent with cost-of-service principals, and the

[23] PECO's tariff includes three (3) night service riders: the Night Service GS Rider, the Night Service HT Rider, and Night Service PD Rider. All three riders offer reduced demand charges for Off-Peak billing demand in excess of On-Peak billing demand, and all three define On-Peak as 8:00 AM to 8:00 PM on Monday – Thursday and 8:00 AM to 4:00 PM on Fridays, except that all hours on holidays are Off-Peak. The difference between the three riders is the base rate to which they apply and the specific charges.

Company therefore proposes to clarify in the tariff that a customer account cannot be simultaneously enrolled in both riders. As of February 29, 2024, no customers are currently enrolled in both the EVFC Rider and the Economic Development Rider.

41. Q. Why does PECO propose that most of the tariff changes take effect on January 1, 2026 and that the clarification concerning other riders take effect on January 1, 2025?

A. The EV-FC Pilot Rider is currently scheduled to run through December 31, 2025, and customers enrolled in the Rider have a reasonable expectation that the current terms of the Rider will be in effect through that date. The proposed modifications to eligibility criteria and rate impacts of the Rider will cause the Rider to be less beneficial to some services than it is today and will cause customers whose DCFCs are installed at premises with other loads to become ineligible for the Rider. Therefore, to eliminate the risk of adverse customers impacts, PECO believes it is appropriate to delay the effect of the proposed program modifications to January 1, 2026 to ensure that the modifications will not cause any customer to receive a lesser benefit from the Rider than what they could have reasonably expected at the time of their application for service.

The Company proposes that, unlike all other proposed modifications to the EVFC Rider, the additions to the Other Riders section shall take effect on January 1, 2025 because these modifications are improving the clarity of the current language of the tariff.

42. Q. Are PECO's proposed modifications to the EV-FC Rider consistent with the Commission's Proposed Policy Statement for Electric Utility Rate Design for Electric Vehicle Charging?

A. Yes. PECO's proposed modifications address several elements of the Commission's Proposed Policy Statement for Electric Utility Rate Design for Electric Vehicle Charging.

Proposed Section 69.3552 of the Policy Statement encourages all electric distribution companies ("EDCs") to develop tariffs with distribution and default service generation rates for the purpose of implementing rates specifically for EV charging customers. Extending the EV-FC Rider would ensure that the Company continues to offer this rate option that is specific to EV charging customers.

Proposed Section 69.3552 also states that EV charging tariffed rates should reflect the actual costs of providing charging infrastructure and services. The EV-FC Rider meets this principal because when PECO extends a new service, the Company assesses the upfront cost of providing that service in comparison to the expected first five years of revenue from that service. For customers on the EV-FC Rider, that calculation takes into account the expected revenue reductions from the Rider, thus ensuring that the applicant for a new DCFC service appropriately pays for any infrastructure that needs to be constructed for their service.

Proposed Section 69.3553 states that EDCs should take into consideration rates for direct current fast chargers, including demand charges. By extending the EV-FC Rider and retaining its usage of demand charges, the Company's proposal ensures an ongoing rate design for customers that own or operate DCFCs.

Finally, proposed Section 69.3554 states that EV charging rates should not discriminate against certain types of electric vehicles or drivers. The Company's proposed modifications to the EV-FC Rider tariff align with this proposal by eliminating eligibility criteria that currently restrict the Rider's availability to public, workplace fleet, and transit applications and also provide eligibility for qualifying services that include both DCFC and L2 chargers.

IV. REPORTING REQUIREMENTS

43. Q. What reporting requirements does PECO propose for the EV Charging Pilot and the EV-FC Rider?

A. PECO proposes to combine reporting for the EV Charging Pilot and the EV-FC Rider Pilot in an annual anonymized public TE Programs report for submission to the Commission in 2026 through 2031. The report will be published by PECO by April 1 of each year and cover the preceding calendar year. PECO will post an electronic copy of the report to its website within 10 business days of its submission to the Commission. Each report will cover all of PECO's TE-related pilots that were approved by the Commission in effect during the calendar year covered by the report. The report will include a narrative summary describing the status, outcomes, and findings from each pilot.

With respect to the EV Charging Pilot, the report will include at least the following information:

a. Number of participating charging ports, by county;

b. Number of participating sites, by county;

c. Aggregate dollar value of incentives provided to participating customers;

d. Aggregate annual kWh consumption of L2 chargers supported, by county;

e. Aggregated load profile information for participating L2 chargers;

f. Number of requests received for participation;

g. Initiated requests not funded;

h. Anonymized reasons why initiated requests were not funded; and

i. A description of where charging infrastructure was installed.

With respect to the EV-FC Rider, the report will include at least the following information:

a. Number of participating sites;

b. Number of participating DCFC charging ports;

c. Cumulative number of sites installed since inception of the pilot;

d. Cumulative number of DCFC charging ports installed since inception;

e. Aggregate annual kWh consumption of participating sites;

f. Aggregated hourly load profile information (kWh) for participating sites; and

g. Aggregated monthly demand (kW) for participating sites.

44. Q. What stakeholder engagement requirements does PECO propose for the EV Charging Pilot and the EV-FC Rider?

A. PECO proposes to continue to convene a collaborative working group meeting at least twice annually through 2030 to discuss opportunities to support the equitable expansion of TE within PECO's service territory. PECO will also maintain a means for interested parties and community stakeholders to join a contact list to receive relevant information in advance of the collaborative and will announce each collaborative to the list at least 30 days in advance of the meeting.

V. CONCLUSION

45. Q. Does this conclude your direct testimony at this time?

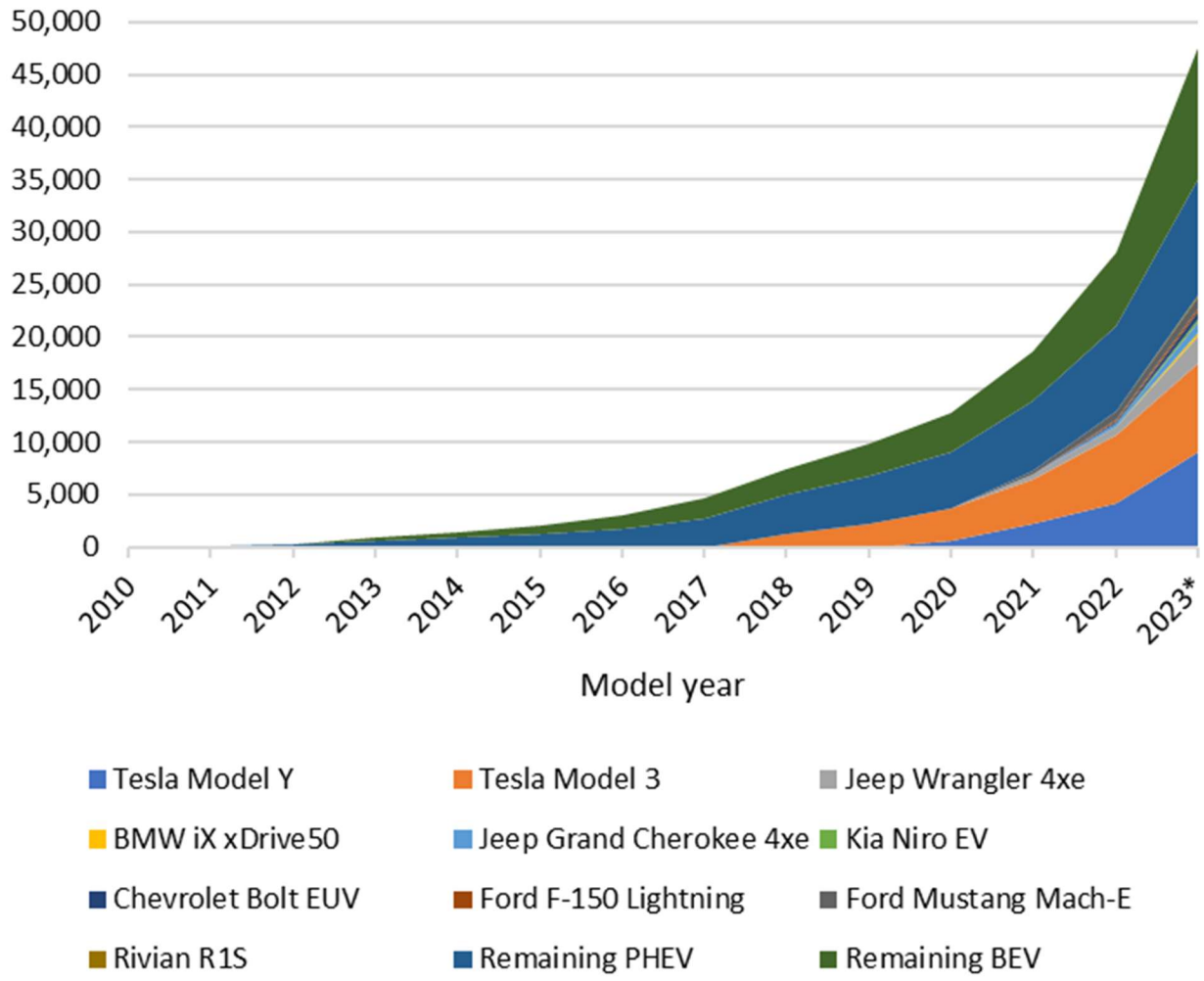
A. Yes, it does.

PECO Exhibit SJD-1:

Forecast Information about EVs and Direct Current Fast Charger Charging Stations in PECO's Service Territory

Plug-in Electric Vehicles on the Road by Year – Historical

EPRI analysis of Experian Data



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	2021	**2022**	**2023**
Plug-in EVs on the road in PECO service territory (rounded)	18,700	28,100	47,500
Note: EPRI's terms of use limit PECO to sharing three rounded data points from the chart above.			

Plug-in Electric Vehicles on the Road by Year – Future Scenarios

This schedule contains passenger and commercial EV projections by the Electric Power Research Institute (EPRI) that represent all on-road transportation within the PECO service territory. The results are divided into one passenger vehicle group and four commercial EV categories:

- The Passenger EV category includes passenger cars and passenger trucks up to Class 2b, with light commercial trucks separated into the next category.
- The Light Commercial Truck category includes light-duty trucks and vans in commercial use in weight classes up to Class 2b.
- The Single Unit Truck category includes box trucks and vans that are rated Class 3 and above, as well as motor homes.
- The Bus + Refuse category includes transit buses, school buses, intercity buses and refuse trucks.
- The Tractor Trailers category includes both short-haul and long-haul big-rig trucks.

Select Data from Scenarios Below			
EV Population (000)	**2024**	**2027**	**2030**
Low Scenario	59	104	157
Medium Scenario	68	168	293
High Scenario	129	423	762
Note: EPRI's use terms limit PECO to sharing three data points for each scenario.			

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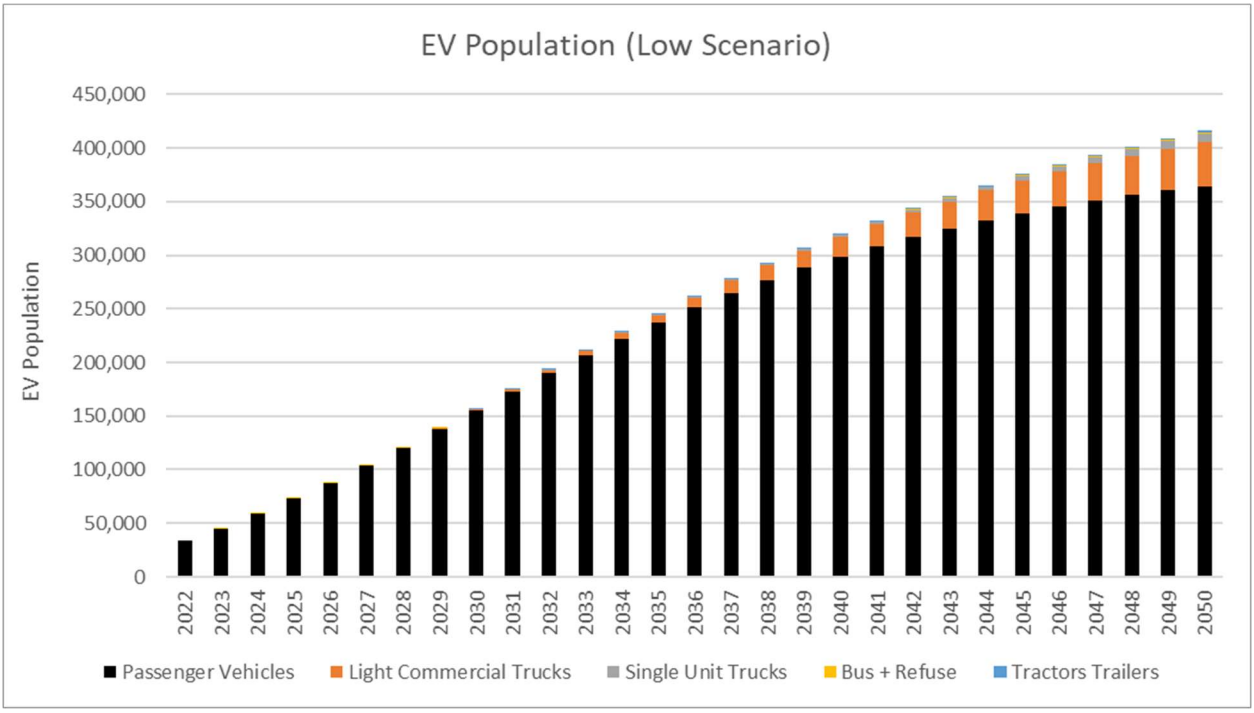
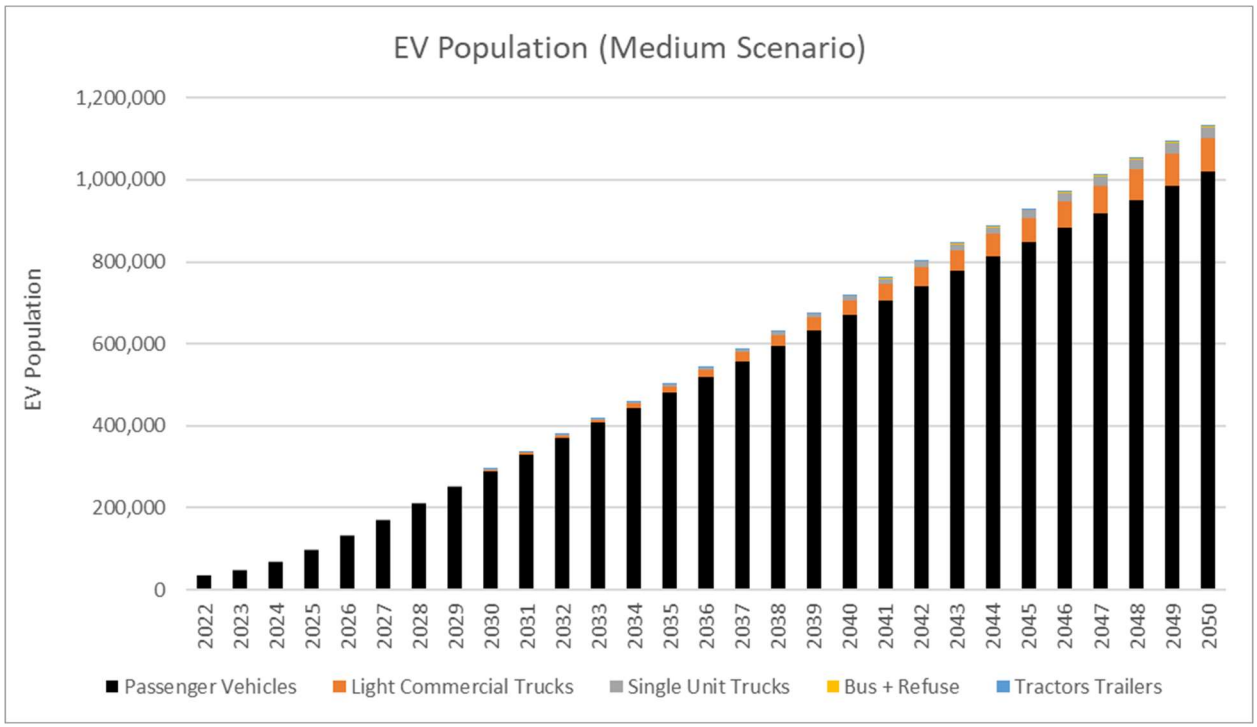
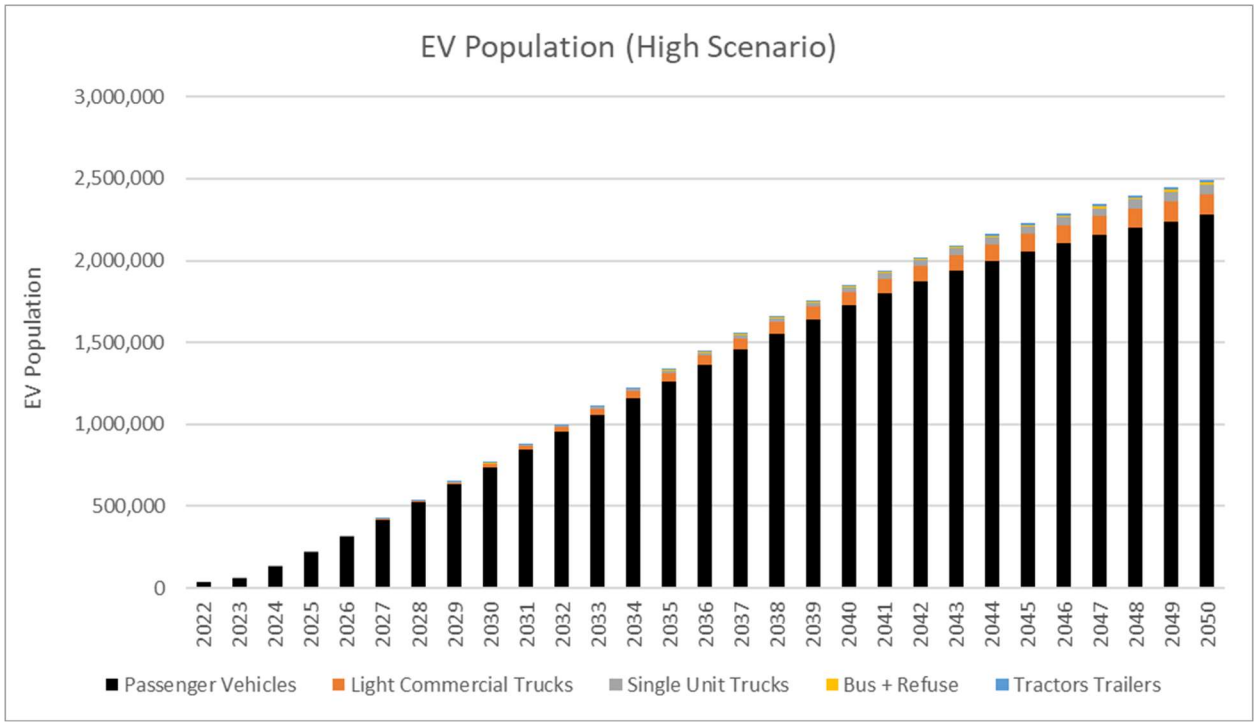



EV Population (Medium Scenario)
EV Population
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050
Passenger Vehicles
Light Commercial Trucks
Single Unit Trucks
Bus + Refuse
Tractors Trailers


EV Population (High Scenario)
EV Population
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050
Passenger Vehicles
Light Commercial Trucks
Single Unit Trucks
Bus + Refuse
Tractors Trailers

Plug-in Electric Vehicles on the Road by Year – Forecasts

	2024	2025	2026	2027	2028	2029	2030
PJM Public Forecast							
Plug-in Electric Vehicle Adjustment to Summer Peak Load for PECO Zone (MW)[1]	24	50	84	120	158	201	246
EVs on Road – Extrapolation from load forecast	66,900	139,375	234,150	334,500	440,425	560,288	685,725
EVs on Road – PECO forecast	63,302	95,535	146,603	225,897	338,007	461,172	590,184
Battery EVs	43,458	66,298	106,684	174,803	275,114	386,613	504,472
Plug-in Hybrid EVs	19,844	29,237	39,919	51,094	62,893	74,559	85,712

Methodology

Extrapolation from PJM load forecast. 2024 EVs on Road are estimated by assuming year over year growth equal to that of 2023. For years beyond 2024, EVs on Road are calculated in proportion to the increase in the PJM plug-in EV adjustment to summer peak load. E.g., the summer peak load adjustment in 2025 is 108% higher than in 2024, so the EVs on Road in 2025 are also 108% higher than in 2024.

PECO internal forecast. The EVs on Road forecast is based on a Systems Dynamics model which is used for the study and analysis of dynamic feedback systems using computer simulation in the proprietary software Vensim. The main sub-modules within the EV System Dynamics model are adoption decision, charging infrastructure, manufacturer capacity and costs, and policy and regulation. Inputs to the model are EV battery price, battery capacity and range, gasoline prices, electricity prices, federal and state tax or rebate policies, charging infrastructure growth, and consumer preferences. The model incorporates the existing buildout of EV charging infrastructure in the PECO service territory as well as the impacts of the National Electric Vehicle Infrastructure (NEVI) program, the Federal Inflation Reduction Act's Clean Vehicle Credit, Pennsylvania's Alternative Fuel Vehicle Rebate, and the Company's EV Charging Pilot. The model determines light-duty electric vehicle adoption over time through an adoption decision for purchasing EV or Internal Combustion Engine (ICE) vehicles.

[1] *See* PJM Load Forecast Report at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx, p. 56.

Forecasts of Number of Accounts on EVFC Rider at Year-end 2027 and 2030

The forecasts below are based on the EPRI plug-in electric vehicle future scenarios shown in Schedule 2 and the plug-in electric vehicle forecasts shown in Schedule 3.

	2024-27	2027-30
EPRI Medium Scenario		
3-year growth in EVs on Road	100,000	125,000
# of new DCFC stations	340	425
Period-end # of DCFC accounts enrolled in EV-FC Rider	57	71
PECO EV Growth Forecast		
3-year growth in EVs on Road	162,595	364,287
# of new DCFC stations	553	1,239
Period-end # of DCFC accounts enrolled in EV-FC Rider	92	206
Extrapolation of PJM Load Forecast		
3-year growth in EVs on Road	267,600	351,225
# of new DCFC stations	910	1,194
Period-end # of DCFC accounts enrolled in EV-FC Rider	152	199
EPRI High Scenario		
3-year growth in EVs on Road	294,000	339,000
# of new DCFC stations	1,000	1,153
Period-end # of DCFC accounts enrolled in EV-FC Rider	167	192

Assumptions

- This forecast uses the ratio of 3.4 DCFC stations per 1,000 EVs developed by the National Renewable Energy Laboratory[2]
- The market will install enough DCFCs stations each to meet the expected growth in EVs in each 3-year period
- The typical new DCFC site will have 6 charging station, consistent with PECO's experience to date

[2] *See* NREL National Plug-In EV Infrastructure Analysis at https://www.nrel.gov/docs/fy18osti/70779.pdf, p. 11.

PECO ENERGY COMPANY
STATEMENT NO. 9-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

REBUTTAL TESTIMONY

WITNESS: STEVEN J. DEMOTT

SUBJECT: ELECTRIC VEHICLE CHARGING PILOTS;
AUTOMATED LOAD MANAGEMENT

DATED: JULY 16, 2024

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IV. CONCLUSION 19

REBUTTAL TESTIMONY
OF
STEVEN J. DEMOTT

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Steven J. DeMott. I am employed by PECO Energy Company ("PECO" or the "Company") as the Senior Manager of Strategic Planning. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct testimony marked as PECO Statement No. 9. My background and qualifications are set forth in that statement.

3. Q. Do you have any corrections to make to your direct testimony?

A. Yes. I have a correction to PECO Statement No. 9, at page 20, lines 8 through 12. The response to question number 26 should have read as follows:

> As of February 29, 2024, there ~~are~~ have been a total of 48 customer accounts enrolled in the EV-FC Rider, and those 48 sites have a total of 282 DCFC stations. All of those sites are publicly available. Of the 48 customer accounts identified, 41 sites with a total of 240 DCFC stations were still enrolled in the rider as of February 29, 2024.

4. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will address the following areas:

Extension and Modification of the Electric Vehicle ("EV") Charging Pilot and Electric Vehicle Fast Charging Pilot Rider (the "EV-FC Rider"): I will

respond to the direct testimony of Mr. Ron Nelson on behalf of the Office of Consumer Advocate ("OCA"), the direct testimony of Mr. Jigar Shah on behalf of Electrify America ("EA"), the direct testimony of Ms. Rhiannon Davis on behalf of EA, the direct testimony of Mr. Dominic G McGraw on behalf of the City of Philadelphia (the "City") and the Philadelphia Energy Authority ("PEA") (collectively, "City/PEA"), and the direct testimony of EVgo witness Lindsey Stegall concerning various topics related to the EV Charging Pilot and EV-FC Rider.

Automated Load Management ("ALM"): I will respond to the direct testimony of Mr. Nelson concerning ALM.

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

A. Yes, I have prepared PECO Exhibit SJD-2.

II. PECO'S ELECTRIC VEHICLE CHARGING PILOTS

6. Q. Did any parties express support for the extension of the EV Charging Pilot and the EV-FC Pilot?

A. Yes. Several parties support the Company continuing and modifying the pilots. OCA witness Nelson, for example, found the proposed modifications to the Company's EV pilots to be "reasonable" and a "directional improvement."[1] EA acknowledged that PECO's proposed extension and modifications to the EV-FC Rider Pilot align with "Pennsylvania's overall [transportation electrification] strategy" and the Commission's draft Policy Statement on EV Charging Rate

[1] *See* OCA St. No. 6, p. 9, line 16, and p. 20, lines 20–21.

Design.[2] EA also supports PECO's proposals to base the demand credit on measured demand and to allow ancillary loads up to one percent of the premises' Direct Current Fast Charging ("DCFC") nameplate capacity to also benefit from the demand credit.[3] EVgo recommended that the Commission approve the proposed extension of and modifications to the EV-FC Rider Pilot.[4] Walmart recommended that the Commission approve the proposed extension of the EV-FC Rider Pilot.[5] Overall, while some parties recommended specific modifications to pilot components or activities, no party expressed a general opposition to the continuation of the pilots.

A. Data Collection, Submetering, and Metrics

7. Q. OCA witness Nelson expresses concern about "persistent" Pilot data collection issues experienced by PECO and contends that the Company is failing to "leverage" the data it collects. Mr. Nelson recommends that PECO's reporting include the number of customers and chargers the Company is not collecting data from. Please respond.

A. Mr. Nelson correctly notes that PECO has identified ongoing challenges in the collection of data in the EV Charging Pilot. However, he misstates the nature of those challenges, incorrectly inferring that "the Company is unable to collect said data." The data collection challenges experienced by the Company have come in two forms: 1) delays in establishing an initial data interface, most often with EV

[2] *See* EA St. No. 1, p. 5, lines 8–18.

[3] *See* EA St. No. 2, p. 5, line 13, through p. 7, line 4.

[4] *See* EVgo St. No. 1, p. 3, lines 2–3.

[5] *See* Walmart St. No. 1, p. 6, lines 14–16 and p. 23, lines 12–14.

service providers ("EVSPs") who have not already established such an interface for an earlier customer in the Pilot, and 2) EVSPs missing service level agreements ("SLAs") for monthly communication of ongoing data once the data interface is established. The Company does not pay out incentives under the Pilot until the initial data interface has been established and the EVSP has successfully transferred the required data to the Pilot administrator. Therefore, these delays – which generally arise from the EVSPs themselves – have no impact on the Company's ability to collect the data. The Pilot administrator has also been successful in addressing each instance of a missed SLA for ongoing data provision, so challenges with the timeliness of data transfer have not resulted in any inability to collect data. Therefore, Mr. Nelson's recommendation that "the Company should report the number of customers and chargers that the Company is and is not collecting data by month"[6] is not appropriate.

Mr. Nelson's concern that the Company has not yet utilized the Pilot data for rate design or capacity planning appears to be based on his inaccurate beliefs that the Company has had "three plus years of collecting data"[7] through the Pilot and that such data collection "has cost ratepayers millions of dollars to collect."[8] In fact, as demonstrated in Table 1 below, the first EV service equipment ("EVSE") incentivized by the Pilot was installed less than two years ago, and only one site had been active for at least four full calendar quarters at the time of Mr. Nelson's

[6] *See* OCA St. No. 6, p. 13, lines 10–11.

[7] *See id.* at p. 11, lines 10–11.

[8] *See id.* at p. 11, lines 20–21.

interrogatory about the use of Pilot data. It is unreasonable to expect that any utility would generalize data from just one Pilot participant for use in capacity planning or rate design. Additionally, as my testimony indicates,[9] PECO had paid out $305,756 of incentives through February 29, 2024, and expended $129,625 in 2022 through 2023 for program administration and data collections, far less than the "millions" asserted by Mr. Nelson.

Table 1. Customer Sites Receiving EV Charging Pilot Incentives

	2022	2023				2024	
	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Customer Sites	1	4	10	6	7	7	1

8. Q. OCA witness Nelson states that "the Company is recommending that each DCFC [participating in the EV-FC Pilot] be separately metered." Please clarify the Company's recommendation.

A. The Company is recommending that each DCFC *site* participating in the Pilot be metered and billed separately from other loads at the premises, e.g., from the business in whose parking lot the DCFCs are located. This will generally require one meter per DCFC site, not a separate meter for each DCFC unit.

9. Q. OCA witness Nelson states that it is reasonable at this time for the Company to separately meter DCFCs as part of the EV-FC Pilot, but the Company should also evaluate submetering with networked EVSE within the EV Charging Pilot and report on the accuracy of the data collected. Do you agree with Mr. Nelson's statement and recommendation?

[9] *See* PECO St. No. 9, p. 9, lines 24–26, and p. 10, lines 3–4.

A. I agree that it is reasonable at this time for the Company to separately meter DCFCs as part of the EV-FC Pilot, but I do not agree that the EV Charging Pilot should be modified to incorporate submetering and reporting on the accuracy of the data collected. Field testing of the accuracy of interval meter data from customer-owned EVSE would require installation of utility-owned submeters in front of each of those devices and synchronization of the internal clocks in each pair of device meters. It would further require creation of a data collection channel for the PECO-owned submeters. In making his recommendation, Mr. Nelson appears to be relying on his misinterpretation of my direct testimony, which I addressed in the section above, that PECO will be installing a submeter on every DCFC device. Mr. Nelson's recommendation also appears to conflate the EV Charging Pilot and the EV-FC Pilot, which are two independent pilots. PECO has no plans to install submeters on any of the devices participating in either pilot and therefore will have no independent data source by which to assess the accuracy of data collected through the EV Charging Pilot. Although PECO has not conducted a formal exploration of the cost of modifying the EV Charging Pilot to include submetering of all participating devices, it appears likely that those costs would consume a significant portion of, if not exceed, the total budget for the EV Charging Pilot. Furthermore, it is unclear whether Mr. Nelson is recommending such a modification.

The Company is aware that utilization of submeters that are integrated into electric vehicles and/or networked EVSE is a viable option for metering electric usage in support of EV-specific rates, and that some utilities, including PECO's

Exelon affiliate Baltimore Gas and Electric, have implemented such approaches. If PECO identifies a future need to validate the accuracy of device-integrated submeters, e.g., in support of a future EV-specific rate, a laboratory approach to such validation would almost certainly be far more cost effective than field testing. Additionally, PECO may never have a need for such validation if Pennsylvania were to follow the examples of Maryland and Minnesota, cited by Mr. Nelson,[10] in waiving accuracy standards for device-integrated submeters.

10. Q. OCA witness Nelson recommends that PECO track fixed metrics related to DCFCs to "help inform when general transportation electrification support is no longer needed from ratepayers." Do you agree with his proposal?

A. No. The transportation electrification market is still in a very early stage of adoption, and there is little data available as to what public EVSE infrastructure will need to look like at maturity, especially to support customers who lack access to dedicated off-street parking at which they could install dedicated EVSE. In the absence of relevant information, any targets set in the near term for metrics related to EVSE availability and ratios would necessarily be arbitrary and risk proving to be wildly inappropriate in the future. Even the metrics used today may prove inappropriate in the future. For example, one of the metrics from my testimony for which Mr. Nelson recommends establishing a target is the percentage of highway interchanges having a DCFC site within one mile that meets National Electric Vehicle Infrastructure ("NEVI") program specifications, e.g., a charging rate of at least 150 kW. I believe that to be an appropriate metric

[10] *See* OCA St. No. 6, p. 14, n. 20.

today because it is based on a national standard, and the data is readily available from the Commonwealth's NEVI implementation program. However, in a mature transportation electrification market, that metric may appear quaint, and travelers may be more interested in the percentage of restaurant parking spaces within one mile of the interchange that offer 350 kW (or faster) chargers, enabling them to recharge while dining.

B. Pilot Term and Rate Design

11. Q. Mr. Nelson believes that PECO's proposed EV-FC Pilot rate design changes are a "directional improvement" but recommends that PECO be required to propose an EV-specific time-of-use rate in its next default service proceeding. Mr. Nelson also argues that both EV Pilots should terminate May 31, 2029 to align with the anticipated end of PECO's next default service plan period. Please respond.

A. Both the EV Charging Pilot and the EV-FC Pilot are available exclusively to non-residential customers. Therefore, in that context, I interpret Mr. Nelson's proposal that PECO be required to propose an EV-specific time-of-use rate in the Company's next default service proceeding to also be specific to non-residential customers, as there is no basis for tying a future residential rate to a proposed extension of a non-residential pilot.

Mr. Nelson's proposal that the Commission require PECO to propose an EV-specific time-of-use rate in the Company's next default service proceeding is problematic in several ways, and the Commission should reject this proposal for the following six reasons.

1) This is a distribution rates proceeding, not a default service proceeding, and it would not be appropriate for the Commission to mandate any specific default service actions in this proceeding.

2) The Commission's draft Policy Statement on EV Charging Rate Design encourages, but does not mandate, electric distribution companies to "consider variable rates for electric vehicle customers based on the time of day and level of demand on the electric grid."[11] Mandating any such rate proposal in this proceeding would be inconsistent with the spirit and intent of the draft policy statement.

3) PECO's current and proposed future default service plans include a time-of-use rate option for Procurement Class 2 customers (up to 100 kW) and hourly pricing for Procurement Class 3/4 customers (over 100 kW). At this time, it is unclear whether non-residential EV charging customers would benefit from or opt into an EV-only time-of-use default service rate.

4) There is little evidence that time-of-use pricing would influence charging behaviors at public charging stations. In the Proposed Policy Statement on EV Charging Rate Design proceeding, EVSPs jointly commented that: "DCFC station operators greatly value customer experience and therefore may be unwilling to pass through extremely elevated peak costs," and they cited a finding by the New York Public Service Commission that public

[11] *See* Electric Utility Rate Design for Electric Vehicle Charging, M-2023-3040755, Proposed Policy Statement Order at Annex A, p. 15 (Nov. 13, 2023).

DCFC station loads are largely inelastic to event-based price signals.[12]

5) It is unclear whether any additional rates will be needed to encourage fleet charging customers to shift charging loads to off-peak hours. In addition to the inherent incentive in demand charges to shift schedulable loads away from the customer's peak usage hours, PECO offers Night Service riders to non-residential customers as an incentive to shift those loads into overnight and weekend hours. Currently, only three fleet charging premises participate in the EV Charging Pilot. As more such customers participate, PECO will gather data to inform decisions as to whether any new rate design is needed for those customers.

6) If PECO determines that one or more new default service rates would be appropriate for EV charging customers, the Company need not wait four years for its next default service proceeding. Rather, the Company would have the option to petition the Commission to modify the DSP to incorporate such rates.

Mr. Nelson's recommendation to change the end date of the EV Charging Pilot and the EV-FC Pilot to align with the anticipated end of PECO's next default service plan period is predicated on his recommendation to require the Company to propose an EV-specific time-of-use rate in the Company's next default service proceeding and should therefore also be rejected by the Commission.

PECO also does not support Mr. Nelson's proposed requirement for PECO to

[12] *See* "Electric Vehicle Service Providers Joint Comments on the Pennsylvania Public Utility Commission's Proposed Policy Statement on EV Charging Rate Design," www.puc.pa.gov/pcdocs/1813441.pdf, p. 6.

provide any proposed EV-specific rate nine months prior to filing of that proposal. As Mr. Nelson concedes, there is no explicit statutory or regulatory requirement for a lengthy pre-filing period,[13] and I am also not aware of the Commission imposing any comparable pre-filing period mandates before a new rate design is filed. Further, such a requirement could adversely affect customers by delaying any stand-alone petition for new EV-specific rates and thus delaying the ultimate availability of such rates.

12. Q. Please summarize EA witness Shah's recommendations concerning PECO's proposed EV-FC Pilot rate design.

A. Mr. Shah supports certain elements of PECO's proposal, such as the allowance of ancillary loads, but objects to *any* minimum billing demand provisions. He further objects to preserving the Rider's existing 36-month term for the demand credit and objects to PECO's current administrative process of basing procurement class and maximum contract demand on the combined nameplate capacity of all DCFCs at a given site. To address his concerns, Mr. Shah recommends that: (1) the demand credit provided by the Rider be extended through December 31, 2030; (2) the Commission prohibit PECO from using nameplate capacity for purposes of determining maximum contract demand or procurement class designation for DCFC sites; and (3) minimum billing demand provisions not apply to customers enrolling in the EV-FC Rider.

13. Q. Do you support the implementation of Mr. Shah's proposed changes?

[13] *See* PECO Exh. SJD-2 (a copy of Mr. Nelson's response to PECO-OCA-II-52).

A. No. Mr. Shah's proposed changes are not consistent with cost-of-service principals and would significantly increase foregone revenue from the Pilot, thus necessitating adjustments to PECO's revenue requirement in this proceeding. PECO believes that the 36-month limit on enrollment in the EV-FC Rider is essential to the Rider's consistency with cost-of-service principles for rate design. By offering a short-term demand credit for DCFC customers, the Company is able to improve the business case for developers to locate new such loads in our service territory while also ensuring that those customers pay their proportionate share of constructing and maintaining the distribution system in the medium and long terms by paying demand charges at the same rates as all other similarly sized customers. Mr. Shah's suggestion would enable DCFCs installed prior to 2023 to regain eligibility for the Rider in 2026 and continue to receive benefits for, in some cases, more than ten years after they were first energized.

PECO believes that as EV market penetration grows, well-sited and managed DCFC sites should be able to take advantage of that growth to achieve increasing capacity factors that enable them to be profitable without electric rate subsidies. This belief is supported by the fact that three sites enrolled in the Rider with nameplate capacities in excess of 500 kW have repeatedly achieved monthly load factors (actual kWh consumption divided by theoretical maximum consumption if every charger were in continuous use at maximum load for the entire month) of 40% or higher.

Mr. Shah's recommendation to eliminate the minimum demand calculation, rather than reduce minimum demand from 40% to 30% of maximum contract demand,

would substantially increase the revenue credits awarded under the EV-FC Pilot. In my direct testimony, I identified that the average value of revenue credits would increase very slightly from $617 to $619 per billing month,[14] based on Rate GS in 2024. Completely eliminating minimum demand would increase the value of demand credits by more than 50%, to $940 per billing month. Assuming modest growth to an average of 50 customers enrolled in the Rider in 2025, that would equate to about $200,000 in additional demand credits.[15] Extrapolating out to 2030, by which time I project the EV-FC Pilot will likely have slightly over 200 enrolled premises,[16] that would equate to about $800,000[17] in additional demand credits. There is no factual basis in this proceeding to establish a compelling need for such a substantial increase in the average demand credit offered by the EV-FC Rider.

Mr. Shah's proposal on determination of maximum contract demand or procurement class designation for DCFC sites is related to PECO's administrative procedures for assessing new loads. Those procedures are independent of the EV-FC Pilot, i.e., they existed prior to implementation of the Pilot, will continue beyond the end of the EV-FC Pilot, and apply to all new EVSE premises regardless of whether or not they participate in the EV-FC Pilot. Maximum contract demand applies to services with anticipated or potential loads in excess

[14] *See* PECO St. No. 9, p. 23, line 20 through p. 24, line 1.

[15] Calculation: ($940 - $619) x 12 months x 50 premises = $192,600; depending on the outcome of this rate case, that value could increase to more than $200,000 at 2025 rates.

[16] *See* PECO St. No. 9, p. 21, lines 3–5.

[17] Calculation: ($940 - $619) x 12 months x 200 premises = $770,400; depending on the outcome of this rate case, that value could increase to more than $800,000 at 2025 rates.

of 500 kW. For DCFC sites, PECO believes that setting the maximum contract demand equal to the combined nameplate capacity of the EVSE at the site is appropriate because the site would be expected to hit that demand when all of the DCFCs are simultaneously in use by EVs capable of charging at the DCFC's maximum rate. This belief is supported by the fact that four DCFC sites enrolled in EV-FC with combined nameplate capacities in excess of 500 kW[18] have achieved measured demand in excess of 80% of their combined nameplate capacities. As EV penetration grows and EV manufacturers continue to develop more models capable of charging at 250 kW or faster, the Company anticipates that DCFC sites will achieve loads nearing or equal to the combined nameplate capacity of their EVSE with increasing frequency. Even if it may take a given site several years to build a customer base large enough to achieve full utilization of the DCFCs, PECO must size distribution system infrastructure to serve that future load, so it is proper that the maximum contract demand reflect that need.

Mr. Shah's recommendation with respect to procurement class determination appears to stem from a misunderstanding of the role of that designation. Procurement class designation is used for determining default service rates for electric generation and has no impact on whether or not a premises will have a maximum contract demand. Additionally, all premises with a maximum demand (contract or measured) in excess of 100 kW, fall into the same procurement class,

[18] I limit this discussion to DCFC sites more than 500 kW for two reasons: 1) sites under 500 kW do not have a maximum contract demand and 2) due to their small number of chargers and the lower nameplate capacities of those chargers, DCFC sites under 500 kW much more frequently achieve high load factors and have measured demands equal to the combined nameplate capacity of the installed DCFCs, so inclusion of them in this analysis would overstate the case for setting maximum contract demand equal to combined nameplate capacity.

and all of Electrify America's premises are significantly larger than 100 kW. Therefore, Mr. Shah's recommendation relative to determination of procurement class is not relevant to this proceeding.

14. Q. EVgo witness Stegall recommends that the Commission approve the proposed extension and modifications to the EV-FC Rider and also direct PECO to evaluate the modified Rider and then put forth a proposal for a permanent EV rate in its next rate case with stakeholder feedback. Do you agree with these recommendations?

A. I agree with the recommendation that the Commission approve the proposed extension and modifications to the EV-FC Rider, but I do not agree that PECO be required to put forth a proposal for a permanent EV rate in its next rate case. It is unclear at this time whether a permanent demand forgiveness rate will be necessary to stimulate development of DCFC infrastructure to serve a growing transportation electrification market. Additionally, as I stated earlier, it is unclear whether any other non-residential rates will be needed to encourage fleet charging customers to shift charging loads to off-peak hours, and EVgo was a party to the comments that I cited earlier in this rebuttal testimony that public DCFC station loads are largely inelastic to event-based price signals. PECO's current combination of demand charges that inherently incentivize customers to shift charging loads away from operational peak hours, and Night Service Riders that directly incentivize customers to shift those charging loads into system off-peak hours, may be sufficient to meet the long-term needs of non-residential customers.

Given these factors, it would be ill-advised for the Commission to order PECO to propose a permanent EV-specific rate for non-residential customers.

C. Implementation Processes

15. Q. City/PEA witness McGraw recommends that PECO permit larger customers, such as the City, to be eligible for up to five individual incentives under the EV Charging Pilot. Do you agree with this recommendation?

A. No. I do not. PECO intentionally structured the incentive limits in the current EV Charging Pilot to apply at the customer, rather than premises, level to ensure equitable access to the limited funding by preventing large multisite customers from monopolizing an excessive share of the budget by submitting applications for multiple sites. In proposing to extend the EV Charging Pilot with a larger annual budget of $940,000 to be shared by the Level 2 Program and the Public Benefit Charging Program, the Company also proposes to replace the original lifetime limit of $60,000 with an annual limit of $60,000 (adjustable within the range of $40,000 to $100,000 based on program demand), thus making the program potentially more generous to larger customers. With approximately $100,000 to $140,000 of the budget dedicated to program administration, the annual incentive budget will be $800,000 to $840,000. Thus, depending on the actual incentive limit for a given calendar year, a single customer that maximizes its incentive eligibility will be able to claim somewhere in the range 5% to 12% of the total incentive budget. As no single customer accounts for 5% of PECO's distribution revenue, every customer that participates in the EV Charging Pilot, including the City of Philadelphia, will have an opportunity to claim an incentive

that is disproportionately large, relative to its size. To my knowledge, no PECO customer other than the City of Philadelphia and perhaps the federal government meet Mr. McGraw's proposed threshold of being a large governmental customer with a fleet in excess of 5,000 vehicles. Implementing Mr. McGraw's recommendation to count those entities as five customers each would allow the City and perhaps the federal government to each claim 25% or more of the total incentive budget, an outcome that would be inequitable to all other PECO customers.

D. <u>Outreach and Education</u>

16. Q. OCA witness Nelson stated that PECO should provide additional support for the Company's projection of $40,000 in EV Toolkit costs each year. Please respond.

A. PECO licenses its EV Toolkit from a third party that provides the web functionality and continuously updates the content as manufacturers release new models of EVs and EVSE. Many utilities, including all of PECO's Exelon affiliates, license some or all of this content. PECO currently licenses only the mass market modules of the Toolkit, which are most applicable to residential and small commercial customers that are considering a purchase of one or two EVs. Exelon has negotiated a subscription rate for PECO of $40,000.

III. AUTOMATED LOAD MANAGEMENT

17. Q. OCA witness Nelson states that PECO appears to be unfamiliar with Automated Load Management ("ALM") and recommends that the Company work with stakeholders on a standard EV charging site evaluation methodology. Please respond.

A. PECO is familiar with ALM and believes that, depending on its implementation cost, it may be a good tool to enable customers with flexibility in charging schedules to manage demand charges and to take maximum advantage of the Company's Night Service Riders. Mr. Nelson's recommendation that the Company educate customers about ALM has merit. However, customer-controlled ALM is not a viable flexible connection approach, even if some utilities in other jurisdictions have been required to offer such flexible connections to their customers.

Software-based ALM systems generally enable their users (PECO's customers) to override or adjust load limits at any time to meet their operational needs. I do not agree with Mr. Nelson that PECO could forego capital expansion investments based on a customer's stated intent to use ALM to limit their loads to the capacity available on the PECO feeder serving their premises. Such a reliance would be foolhardy given that the fleet or facility managers who operate such ALM systems have a primary responsibility to meet the needs of their own customers. Indeed, were PECO to install an ALM system for its own fleet, the Company would not be willing to commit to itself that it would never override load limits, e.g., to recharge vehicles in support of power restoration activities after a storm. To rely

on software-based ALM to avoid capacity expansion for the feeder serving a specific customer, the Company would need contractual penalties for a single instance of exceeding the agreed upon load equal to the full cost of the foregone capacity expansion (as such an instance would be proof that the capacity expansion is necessary) plus unlimited liability for any damage done to any PECO distribution or substation equipment by the excess load. The Company may also find it necessary for a software-based ALM flexible interconnection customer to indemnify PECO against any damage claims by other customers resulting from the excess load.

This is not to say that PECO rejects all possible approaches to flexible interconnection. For example, battery-integrated charging, in which EVSE is supplied by a battery storage system that is trickle charged from the PECO distribution system (and possibly from a solar array), could provide a hardware-based guarantee that charging loads will never exceed the available feeder capacity. Although such approaches are often cost prohibitive at current battery storage prices, PECO is open to evaluating such options on a case-by-case basis if a customer were to want to pursue them.

IV. CONCLUSION

18. Q. Does this complete your rebuttal testimony at this time?

A. Yes. It does.

PECO ENERGY COMPANY
STATEMENT NO. 9-R (Corrected Version)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

REBUTTAL TESTIMONY

WITNESS: STEVEN J. DEMOTT

SUBJECT: ELECTRIC VEHICLE CHARGING PILOTS;
AUTOMATED LOAD MANAGEMENT

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
STEVEN J. DEMOTT

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Steven J. DeMott. I am employed by PECO Energy Company ("PECO" or the "Company") as the Senior Manager of Strategic Planning. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct testimony marked as PECO Statement No. 9. My background and qualifications are set forth in that statement.

3. Q. Do you have any corrections to make to your direct testimony?

A. Yes. I have a correction to PECO Statement No. 9, at page 20, lines 8 through 12. The response to question number 26 should have read as follows:

> As of February 29, 2024, there ~~are~~ have been a total of 48 customer accounts enrolled in the EV-FC Rider, and those 48 sites have a total of 282 DCFC stations. All of those sites are publicly available. Of the 48 customer accounts identified, 41 sites with a total of 240 DCFC stations were still enrolled in the rider as of February 29, 2024.

4. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will address the following areas:

Extension and Modification of the Electric Vehicle ("EV") Charging Pilot and Electric Vehicle Fast Charging Pilot Rider (the "EV-FC Rider"): I will

respond to the direct testimony of Mr. Ron Nelson on behalf of the Office of Consumer Advocate ("OCA"), the direct testimony of Mr. Jigar Shah on behalf of Electrify America ("EA"), the direct testimony of Ms. Rhiannon Davis on behalf of EA, the direct testimony of Mr. Dominic G McGraw on behalf of the City of Philadelphia (the "City") and the Philadelphia Energy Authority ("PEA") (collectively, "City/PEA"), and the direct testimony of EVgo witness Lindsey Stegall concerning various topics related to the EV Charging Pilot and EV-FC Rider.

Automated Load Management ("ALM"): I will respond to the direct testimony of Mr. Nelson concerning ALM.

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

A. Yes, I have prepared PECO Exhibit SJD-2.

II. PECO'S ELECTRIC VEHICLE CHARGING PILOTS

6. Q. Did any parties express support for the extension of the EV Charging Pilot and the EV-FC Pilot?

A. Yes. Several parties support the Company continuing and modifying the pilots. OCA witness Nelson, for example, found the proposed modifications to the Company's EV pilots to be "reasonable" and a "directional improvement."[1] EA acknowledged that PECO's proposed extension and modifications to the EV-FC Rider Pilot align with "Pennsylvania's overall [transportation electrification] strategy" and the Commission's draft Policy Statement on EV Charging Rate

[1] *See* OCA St. No. 6, p. 9, line 16, and p. 20, lines 20–21.

Design.[2] EA also supports PECO's proposals to base the demand credit on measured demand and to allow ancillary loads up to one percent of the premises' Direct Current Fast Charging ("DCFC") nameplate capacity to also benefit from the demand credit.[3] EVgo recommended that the Commission approve the proposed extension of and modifications to the EV-FC Rider Pilot.[4] Walmart recommended that the Commission approve the proposed extension of the EV-FC Rider Pilot.[5] Overall, while some parties recommended specific modifications to pilot components or activities, no party expressed a general opposition to the continuation of the pilots.

A. <u>Data Collection, Submetering, and Metrics</u>

7. Q. OCA witness Nelson expresses concern about "persistent" Pilot data collection issues experienced by PECO and contends that the Company is failing to "leverage" the data it collects. Mr. Nelson recommends that PECO's reporting include the number of customers and chargers the Company is not collecting data from. Please respond.

A. Mr. Nelson correctly notes that PECO has identified ongoing challenges in the collection of data in the EV Charging Pilot. However, he misstates the nature of those challenges, incorrectly inferring that "the Company is unable to collect said data." The data collection challenges experienced by the Company have come in two forms: 1) delays in establishing an initial data interface, most often with EV

[2] *See* EA St. No. 1, p. 5, lines 8–18.

[3] *See* EA St. No. 2, p. 5, line 13, through p. 7, line 4.

[4] *See* EVgo St. No. 1, p. 3, lines 2–3.

[5] *See* Walmart St. No. 1, p. 6, lines 14–16 and p. 23, lines 12–14.

service providers ("EVSPs") who have not already established such an interface for an earlier customer in the Pilot, and 2) EVSPs missing service level agreements ("SLAs") for monthly communication of ongoing data once the data interface is established. The Company does not pay out incentives under the Pilot until the initial data interface has been established and the EVSP has successfully transferred the required data to the Pilot administrator. Therefore, these delays – which generally arise from the EVSPs themselves – have no impact on the Company's ability to collect the data. The Pilot administrator has also been successful in addressing each instance of a missed SLA for ongoing data provision, so challenges with the timeliness of data transfer have not resulted in any inability to collect data. Therefore, Mr. Nelson's recommendation that "the Company should report the number of customers and chargers that the Company is and is not collecting data by month"[6] is not appropriate.

Mr. Nelson's concern that the Company has not yet utilized the Pilot data for rate design or capacity planning appears to be based on his inaccurate beliefs that the Company has had "three plus years of collecting data"[7] through the Pilot and that such data collection "has cost ratepayers millions of dollars to collect."[8] In fact, as demonstrated in Table 1 below, the first EV service equipment ("EVSE") incentivized by the Pilot was installed less than two years ago, and only five sites had been active for at least four full calendar quarters at the time of Mr. Nelson's

[6] *See* OCA St. No. 6, p. 13, lines 10–11.

[7] *See id.* at p. 11, lines 10–11.

[8] *See id.* at p. 11, lines 20–21.

interrogatory about the use of Pilot data. It is unreasonable to expect that any utility would generalize data from just five Pilot participants for use in capacity planning or rate design. Additionally, as my testimony indicates,[9] PECO had paid out $305,756 of incentives through February 29, 2024, and expended $129,625 in 2022 through 2023 for program administration and data collections, far less than the "millions" asserted by Mr. Nelson.

Table 1. Customer Sites Receiving EV Charging Pilot Incentives

	2022	2023				2024	
	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Customer Sites	1	4	10	6	7	7	1

8. Q. OCA witness Nelson states that "the Company is recommending that each DCFC [participating in the EV-FC Pilot] be separately metered." Please clarify the Company's recommendation.

A. The Company is recommending that each DCFC *site* participating in the Pilot be metered and billed separately from other loads at the premises, e.g., from the business in whose parking lot the DCFCs are located. This will generally require one meter per DCFC site, not a separate meter for each DCFC unit.

9. Q. OCA witness Nelson states that it is reasonable at this time for the Company to separately meter DCFCs as part of the EV-FC Pilot, but the Company should also evaluate submetering with networked EVSE within the EV Charging Pilot and report on the accuracy of the data collected. Do you agree with Mr. Nelson's statement and recommendation?

[9] *See* PECO St. No. 9, p. 9, lines 24–26, and p. 10, lines 3–4.

A. I agree that it is reasonable at this time for the Company to separately meter DCFCs as part of the EV-FC Pilot, but I do not agree that the EV Charging Pilot should be modified to incorporate submetering and reporting on the accuracy of the data collected. Field testing of the accuracy of interval meter data from customer-owned EVSE would require installation of utility-owned submeters in front of each of those devices and synchronization of the internal clocks in each pair of device meters. It would further require creation of a data collection channel for the PECO-owned submeters. In making his recommendation, Mr. Nelson appears to be relying on his misinterpretation of my direct testimony, which I addressed in the section above, that PECO will be installing a submeter on every DCFC device. Mr. Nelson's recommendation also appears to conflate the EV Charging Pilot and the EV-FC Pilot, which are two independent pilots. PECO has no plans to install submeters on any of the devices participating in either pilot and therefore will have no independent data source by which to assess the accuracy of data collected through the EV Charging Pilot. Although PECO has not conducted a formal exploration of the cost of modifying the EV Charging Pilot to include submetering of all participating devices, it appears likely that those costs would consume a significant portion of, if not exceed, the total budget for the EV Charging Pilot. Furthermore, it is unclear whether Mr. Nelson is recommending such a modification.

The Company is aware that utilization of submeters that are integrated into electric vehicles and/or networked EVSE is a viable option for metering electric usage in support of EV-specific rates, and that some utilities, including PECO's

Exelon affiliate Baltimore Gas and Electric, have implemented such approaches. If PECO identifies a future need to validate the accuracy of device-integrated submeters, e.g., in support of a future EV-specific rate, a laboratory approach to such validation would almost certainly be far more cost effective than field testing. Additionally, PECO may never have a need for such validation if Pennsylvania were to follow the examples of Maryland and Minnesota, cited by Mr. Nelson,[10] in waiving accuracy standards for device-integrated submeters.

10. Q. OCA witness Nelson recommends that PECO track fixed metrics related to DCFCs to "help inform when general transportation electrification support is no longer needed from ratepayers." Do you agree with his proposal?

A. No. The transportation electrification market is still in a very early stage of adoption, and there is little data available as to what public EVSE infrastructure will need to look like at maturity, especially to support customers who lack access to dedicated off-street parking at which they could install dedicated EVSE. In the absence of relevant information, any targets set in the near term for metrics related to EVSE availability and ratios would necessarily be arbitrary and risk proving to be wildly inappropriate in the future. Even the metrics used today may prove inappropriate in the future. For example, one of the metrics from my testimony for which Mr. Nelson recommends establishing a target is the percentage of highway interchanges having a DCFC site within one mile that meets National Electric Vehicle Infrastructure ("NEVI") program specifications, e.g., a charging rate of at least 150 kW. I believe that to be an appropriate metric

[10] *See* OCA St. No. 6, p. 14, n. 20.

today because it is based on a national standard, and the data is readily available from the Commonwealth's NEVI implementation program. However, in a mature transportation electrification market, that metric may appear quaint, and travelers may be more interested in the percentage of restaurant parking spaces within one mile of the interchange that offer 350 kW (or faster) chargers, enabling them to recharge while dining.

B. Pilot Term and Rate Design

11. Q. Mr. Nelson believes that PECO's proposed EV-FC Pilot rate design changes are a "directional improvement" but recommends that PECO be required to propose an EV-specific time-of-use rate in its next default service proceeding. Mr. Nelson also argues that both EV Pilots should terminate May 31, 2029 to align with the anticipated end of PECO's next default service plan period. Please respond.

A. Both the EV Charging Pilot and the EV-FC Pilot are available exclusively to non-residential customers. Therefore, in that context, I interpret Mr. Nelson's proposal that PECO be required to propose an EV-specific time-of-use rate in the Company's next default service proceeding to also be specific to non-residential customers, as there is no basis for tying a future residential rate to a proposed extension of a non-residential pilot.

Mr. Nelson's proposal that the Commission require PECO to propose an EV-specific time-of-use rate in the Company's next default service proceeding is problematic in several ways, and the Commission should reject this proposal for the following six reasons.

1) This is a distribution rates proceeding, not a default service proceeding, and it would not be appropriate for the Commission to mandate any specific default service actions in this proceeding.

2) The Commission's draft Policy Statement on EV Charging Rate Design encourages, but does not mandate, electric distribution companies to "consider variable rates for electric vehicle customers based on the time of day and level of demand on the electric grid."[11] Mandating any such rate proposal in this proceeding would be inconsistent with the spirit and intent of the draft policy statement.

3) PECO's current and proposed future default service plans include a time-of-use rate option for Procurement Class 2 customers (up to 100 kW) and hourly pricing for Procurement Class 3/4 customers (over 100 kW). At this time, it is unclear whether non-residential EV charging customers would benefit from or opt into an EV-only time-of-use default service rate.

4) There is little evidence that time-of-use pricing would influence charging behaviors at public charging stations. In the Proposed Policy Statement on EV Charging Rate Design proceeding, EVSPs jointly commented that: "DCFC station operators greatly value customer experience and therefore may be unwilling to pass through extremely elevated peak costs," and they cited a finding by the New York Public Service Commission that public

[11] *See* Electric Utility Rate Design for Electric Vehicle Charging, M-2023-3040755, Proposed Policy Statement Order at Annex A, p. 15 (Nov. 13, 2023).

DCFC station loads are largely inelastic to event-based price signals.[12]

5) It is unclear whether any additional rates will be needed to encourage fleet charging customers to shift charging loads to off-peak hours. In addition to the inherent incentive in demand charges to shift schedulable loads away from the customer's peak usage hours, PECO offers Night Service riders to non-residential customers as an incentive to shift those loads into overnight and weekend hours. Currently, only three fleet charging premises participate in the EV Charging Pilot. As more such customers participate, PECO will gather data to inform decisions as to whether any new rate design is needed for those customers.

6) If PECO determines that one or more new default service rates would be appropriate for EV charging customers, the Company need not wait four years for its next default service proceeding. Rather, the Company would have the option to petition the Commission to modify the DSP to incorporate such rates.

Mr. Nelson's recommendation to change the end date of the EV Charging Pilot and the EV-FC Pilot to align with the anticipated end of PECO's next default service plan period is predicated on his recommendation to require the Company to propose an EV-specific time-of-use rate in the Company's next default service proceeding and should therefore also be rejected by the Commission.

PECO also does not support Mr. Nelson's proposed requirement for PECO to

[12] *See* "Electric Vehicle Service Providers Joint Comments on the Pennsylvania Public Utility Commission's Proposed Policy Statement on EV Charging Rate Design," www.puc.pa.gov/pcdocs/1813441.pdf, p. 6.

provide any proposed EV-specific rate nine months prior to filing of that proposal. As Mr. Nelson concedes, there is no explicit statutory or regulatory requirement for a lengthy pre-filing period,[13] and I am also not aware of the Commission imposing any comparable pre-filing period mandates before a new rate design is filed. Further, such a requirement could adversely affect customers by delaying any stand-alone petition for new EV-specific rates and thus delaying the ultimate availability of such rates.

12. Q. Please summarize EA witness Shah's recommendations concerning PECO's proposed EV-FC Pilot rate design.

A. Mr. Shah supports certain elements of PECO's proposal, such as the allowance of ancillary loads, but objects to *any* minimum billing demand provisions. He further objects to preserving the Rider's existing 36-month term for the demand credit and objects to PECO's current administrative process of basing procurement class and maximum contract demand on the combined nameplate capacity of all DCFCs at a given site. To address his concerns, Mr. Shah recommends that: (1) the demand credit provided by the Rider be extended through December 31, 2030; (2) the Commission prohibit PECO from using nameplate capacity for purposes of determining maximum contract demand or procurement class designation for DCFC sites; and (3) minimum billing demand provisions not apply to customers enrolling in the EV-FC Rider.

13. Q. Do you support the implementation of Mr. Shah's proposed changes?

[13] *See* PECO Exh. SJD-2 (a copy of Mr. Nelson's response to PECO-OCA-II-52).

A. No. Mr. Shah's proposed changes are not consistent with cost-of-service principals and would significantly increase foregone revenue from the Pilot, thus necessitating adjustments to PECO's revenue requirement in this proceeding. PECO believes that the 36-month limit on enrollment in the EV-FC Rider is essential to the Rider's consistency with cost-of-service principles for rate design. By offering a short-term demand credit for DCFC customers, the Company is able to improve the business case for developers to locate new such loads in our service territory while also ensuring that those customers pay their proportionate share of constructing and maintaining the distribution system in the medium and long terms by paying demand charges at the same rates as all other similarly sized customers. Mr. Shah's suggestion would enable DCFCs installed prior to 2023 to regain eligibility for the Rider in 2026 and continue to receive benefits for, in some cases, more than ten years after they were first energized.

PECO believes that as EV market penetration grows, well-sited and managed DCFC sites should be able to take advantage of that growth to achieve increasing capacity factors that enable them to be profitable without electric rate subsidies. This belief is supported by the fact that three sites enrolled in the Rider with nameplate capacities in excess of 500 kW have repeatedly achieved monthly load factors (actual kWh consumption divided by theoretical maximum consumption if every charger were in continuous use at maximum load for the entire month) of 40% or higher.

Mr. Shah's recommendation to eliminate the minimum demand calculation, rather than reduce minimum demand from 40% to 30% of maximum contract demand,

would substantially increase the revenue credits awarded under the EV-FC Pilot. In my direct testimony, I identified that the average value of revenue credits would increase very slightly from $617 to $619 per billing month,[14] based on Rate GS in 2024. Completely eliminating minimum demand would increase the value of demand credits by more than 50%, to $940 per billing month. Assuming modest growth to an average of 50 customers enrolled in the Rider in 2025, that would equate to about $200,000 in additional demand credits.[15] Extrapolating out to 2030, by which time I project the EV-FC Pilot will likely have slightly over 200 enrolled premises,[16] that would equate to about $800,000[17] in additional demand credits. There is no factual basis in this proceeding to establish a compelling need for such a substantial increase in the average demand credit offered by the EV-FC Rider.

Mr. Shah's proposal on determination of maximum contract demand or procurement class designation for DCFC sites is related to PECO's administrative procedures for assessing new loads. Those procedures are independent of the EV-FC Pilot, i.e., they existed prior to implementation of the Pilot, will continue beyond the end of the EV-FC Pilot, and apply to all new EVSE premises regardless of whether or not they participate in the EV-FC Pilot. Maximum contract demand applies to services with anticipated or potential loads in excess

[14] *See* PECO St. No. 9, p. 23, line 20 through p. 24, line 1.

[15] Calculation: ($940 - $619) x 12 months x 50 premises = $192,600; depending on the outcome of this rate case, that value could increase to more than $200,000 at 2025 rates.

[16] *See* PECO St. No. 9, p. 21, lines 3–5.

[17] Calculation: ($940 - $619) x 12 months x 200 premises = $770,400; depending on the outcome of this rate case, that value could increase to more than $800,000 at 2025 rates.

of 500 kW. For DCFC sites, PECO believes that setting the maximum contract demand equal to the combined nameplate capacity of the EVSE at the site is appropriate because the site would be expected to hit that demand when all of the DCFCs are simultaneously in use by EVs capable of charging at the DCFC's maximum rate. This belief is supported by the fact that four DCFC sites enrolled in EV-FC with combined nameplate capacities in excess of 500 kW[18] have achieved measured demand in excess of 80% of their combined nameplate capacities. As EV penetration grows and EV manufacturers continue to develop more models capable of charging at 250 kW or faster, the Company anticipates that DCFC sites will achieve loads nearing or equal to the combined nameplate capacity of their EVSE with increasing frequency. Even if it may take a given site several years to build a customer base large enough to achieve full utilization of the DCFCs, PECO must size distribution system infrastructure to serve that future load, so it is proper that the maximum contract demand reflect that need.

Mr. Shah's recommendation with respect to procurement class determination appears to stem from a misunderstanding of the role of that designation. Procurement class designation is used for determining default service rates for electric generation and has no impact on whether or not a premises will have a maximum contract demand. Additionally, all premises with a maximum demand (contract or measured) in excess of 100 kW, fall into the same procurement class,

[18] I limit this discussion to DCFC sites more than 500 kW for two reasons: 1) sites under 500 kW do not have a maximum contract demand and 2) due to their small number of chargers and the lower nameplate capacities of those chargers, DCFC sites under 500 kW much more frequently achieve high load factors and have measured demands equal to the combined nameplate capacity of the installed DCFCs, so inclusion of them in this analysis would overstate the case for setting maximum contract demand equal to combined nameplate capacity.

and all of Electrify America's premises are significantly larger than 100 kW. Therefore, Mr. Shah's recommendation relative to determination of procurement class is not relevant to this proceeding.

14. Q. EVgo witness Stegall recommends that the Commission approve the proposed extension and modifications to the EV-FC Rider and also direct PECO to evaluate the modified Rider and then put forth a proposal for a permanent EV rate in its next rate case with stakeholder feedback. Do you agree with these recommendations?

A. I agree with the recommendation that the Commission approve the proposed extension and modifications to the EV-FC Rider, but I do not agree that PECO be required to put forth a proposal for a permanent EV rate in its next rate case. It is unclear at this time whether a permanent demand forgiveness rate will be necessary to stimulate development of DCFC infrastructure to serve a growing transportation electrification market. Additionally, as I stated earlier, it is unclear whether any other non-residential rates will be needed to encourage fleet charging customers to shift charging loads to off-peak hours, and EVgo was a party to the comments that I cited earlier in this rebuttal testimony that public DCFC station loads are largely inelastic to event-based price signals. PECO's current combination of demand charges that inherently incentivize customers to shift charging loads away from operational peak hours, and Night Service Riders that directly incentivize customers to shift those charging loads into system off-peak hours, may be sufficient to meet the long-term needs of non-residential customers.

Given these factors, it would be ill-advised for the Commission to order PECO to propose a permanent EV-specific rate for non-residential customers.

C. <u>Implementation Processes</u>

15. Q. City/PEA witness McGraw recommends that PECO permit larger customers, such as the City, to be eligible for up to five individual incentives under the EV Charging Pilot. Do you agree with this recommendation?

A. No. I do not. PECO intentionally structured the incentive limits in the current EV Charging Pilot to apply at the customer, rather than premises, level to ensure equitable access to the limited funding by preventing large multisite customers from monopolizing an excessive share of the budget by submitting applications for multiple sites. In proposing to extend the EV Charging Pilot with a larger annual budget of $940,000 to be shared by the Level 2 Program and the Public Benefit Charging Program, the Company also proposes to replace the original lifetime limit of $60,000 with an annual limit of $60,000 (adjustable within the range of $40,000 to $100,000 based on program demand), thus making the program potentially more generous to larger customers. With approximately $100,000 to $140,000 of the budget dedicated to program administration, the annual incentive budget will be $800,000 to $840,000. Thus, depending on the actual incentive limit for a given calendar year, a single customer that maximizes its incentive eligibility will be able to claim somewhere in the range 5% to 12% of the total incentive budget. As no single customer accounts for 5% of PECO's distribution revenue, every customer that participates in the EV Charging Pilot, including the City of Philadelphia, will have an opportunity to claim an incentive

that is disproportionately large, relative to its size. To my knowledge, no PECO customer other than the City of Philadelphia and perhaps the federal government meet Mr. McGraw's proposed threshold of being a large governmental customer with a fleet in excess of 5,000 vehicles. Implementing Mr. McGraw's recommendation to count those entities as five customers each would allow the City and perhaps the federal government to each claim 25% or more of the total incentive budget, an outcome that would be inequitable to all other PECO customers.

D. <u>Outreach and Education</u>

16. Q. OCA witness Nelson stated that PECO should provide additional support for the Company's projection of $40,000 in EV Toolkit costs each year. Please respond.

A. PECO licenses its EV Toolkit from a third party that provides the web functionality and continuously updates the content as manufacturers release new models of EVs and EVSE. Many utilities, including all of PECO's Exelon affiliates, license some or all of this content. PECO currently licenses only the mass market modules of the Toolkit, which are most applicable to residential and small commercial customers that are considering a purchase of one or two EVs. Exelon has negotiated a subscription rate for PECO of $40,000.

III. AUTOMATED LOAD MANAGEMENT

17. Q. OCA witness Nelson states that PECO appears to be unfamiliar with Automated Load Management ("ALM") and recommends that the Company work with stakeholders on a standard EV charging site evaluation methodology. Please respond.

A. PECO is familiar with ALM and believes that, depending on its implementation cost, it may be a good tool to enable customers with flexibility in charging schedules to manage demand charges and to take maximum advantage of the Company's Night Service Riders. Mr. Nelson's recommendation that the Company educate customers about ALM has merit. However, customer-controlled ALM is not a viable flexible connection approach, even if some utilities in other jurisdictions have been required to offer such flexible connections to their customers.

Software-based ALM systems generally enable their users (PECO's customers) to override or adjust load limits at any time to meet their operational needs. I do not agree with Mr. Nelson that PECO could forego capital expansion investments based on a customer's stated intent to use ALM to limit their loads to the capacity available on the PECO feeder serving their premises. Such a reliance would be foolhardy given that the fleet or facility managers who operate such ALM systems have a primary responsibility to meet the needs of their own customers. Indeed, were PECO to install an ALM system for its own fleet, the Company would not be willing to commit to itself that it would never override load limits, e.g., to recharge vehicles in support of power restoration activities after a storm. To rely

on software-based ALM to avoid capacity expansion for the feeder serving a specific customer, the Company would need contractual penalties for a single instance of exceeding the agreed upon load equal to the full cost of the foregone capacity expansion (as such an instance would be proof that the capacity expansion is necessary) plus unlimited liability for any damage done to any PECO distribution or substation equipment by the excess load. The Company may also find it necessary for a software-based ALM flexible interconnection customer to indemnify PECO against any damage claims by other customers resulting from the excess load.

This is not to say that PECO rejects all possible approaches to flexible interconnection. For example, battery-integrated charging, in which EVSE is supplied by a battery storage system that is trickle charged from the PECO distribution system (and possibly from a solar array), could provide a hardware-based guarantee that charging loads will never exceed the available feeder capacity. Although such approaches are often cost prohibitive at current battery storage prices, PECO is open to evaluating such options on a case-by-case basis if a customer were to want to pursue them.

IV. CONCLUSION

18. Q. Does this complete your rebuttal testimony at this time?

A. Yes. It does.

PECO Energy Company, R-2024-3046931 (Electric)

PECO Interrogatories to the Office of Consumer Advocate
Set II

PECO-OCA-II-52. Please refer to OCA Statement No. 6, page 22, lines 4-7. Please identify and provide any Pennsylvania statute, regulation, or other requirement requiring a public utility to conduct a rate design pre-filing brief nine months prior to filing a petition for the rate.

Response:

Mr. Nelson is not aware of any statute or requirement, nor did he conduct analysis looking for such information because identifying a legal requirement was not a necessary predicate for his recommendation. Commissions have broad authority and can require filings from utilities without any explicit rule or statute, and Mr. Nelson's recommendation is intended, in part, to ensure that the Commission will have adequate information to evaluate PECO's programming.

Dated: July 1, 2024

Sponsored by: Ron Nelson

PECO ENERGY COMPANY
STATEMENT NO. 9-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

SURREBUTTAL TESTIMONY

WITNESS: STEVEN J. DEMOTT

SUBJECT: PECO'S ELECTRIC VEHICLE FAST CHARGING PILOT RIDER

DATED: AUGUST 2, 2024

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SURREBUTTAL TESTIMONY
OF
STEVEN J. DEMOTT

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Steven J. DeMott. I am employed by PECO Energy Company ("PECO" or the "Company") as the Senior Manager of Strategic Planning. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct and rebuttal testimony on behalf of the Company, which are designated as PECO Statement Nos. 9 and 9-R, respectively.

3. Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the rebuttal testimony of EVgo witness Lindsay Stegall regarding PECO's Electric Vehicle Fast Charging Pilot Rider (the "EV-FC Rider").

II. PECO'S EV-FC Rider

4. Q. Ms. Stegall states that PECO's proposed minimum demand level for the EV-FC Rider "may continue to preclude many stations from reaping the benefits of the rider and subsequently provide little to no demand charge relief for those stations. For instance, stations located in rural areas or other less dense areas will experience lower utilization rates, resulting in stations that may not achieve the minimum demand required to receive the benefit of the rider." Do you agree with this statement?

A. No. The belief that stations with lower utilization will not benefit from the proposed structure of the EV-FC Rider demand credit reflects a misunderstanding of the mathematics of the proposed rate. The operation of the demand credit is best demonstrated with an extreme example. In this example, we will assume a Direct Current Fast Charging ("DCFC") premises with a total nameplate charging capacity of 1,000 kilowatts. This premises would have a minimum demand of 400 kilowatts (40% of 1,000) under the base Rate GS and a minimum demand of 300 kilowatts (30% of maximum demand) under the proposed modification to the EV-FC Rider. If that DCFC premises had a measured demand of 50 kilowatts in a given month, it would bill at 400 kilowatts under the base Rate GS and at 300 kilowatts under the proposed modification to the EV-FC Rider. That means that the Rider would offer this extremely underutilized station a 25% demand credit ((400-300)/400=25%), whereas a moderately or heavily utilized station (one with measured demand greater than or equal to 50% of its nameplate charging capacity) would receive a 20% demand credit. Thus, the Rider with PECO's

proposed modifications is more beneficial to underutilized stations than to heavily utilized stations.

While the billing demand of 300 kilowatts in this scenario is significantly higher than the measured demand of 50 kilowatts, it is justified because PECO would have installed a dedicated transformer and other equipment to serve a load of up to 1,000 kilowatts. Maintaining a minimum demand calculation, as PECO has proposed in this proceeding, ensures that such costs are appropriately recovered from the customer who benefits from the dedicated transformer instead of such costs being socialized to other customers who do not benefit from the transformer.

III. CONCLUSION

6. Q. Does this complete your surrebuttal testimony at this time?

A. Yes. It does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046931**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Steven J. DeMott, hereby state that I am the Senior Manager of Strategic Planning for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 9
- PECO Exhibit SJD-1

- PECO Statement No. 9-R (Corrected Version)
- PECO Exhibit SJD-2

- PECO Statement No. 9-SR

Dated: August 5, 2024

Steven J. DeMott

PECO Statement No. 10:

Direct Testimony of Jacqueline F. Golden

PECO ENERGY COMPANY
STATEMENT NO. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

DIRECT TESTIMONY

WITNESS: JACQUELINE F. GOLDEN

SUBJECTS: RECOVERY OF CAP COSTS; EXISTING UNIVERSAL SERVICE PROGRAMS; REVISIONS TO THE MATCHING ENERGY ASSISTANCE FUND; AND EXPANDED CUSTOMER OUTREACH AND EDUCATION

DATED: MARCH 28, 2024

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DIRECT TESTIMONY
OF
JACQUELINE F. GOLDEN

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Jacqueline F. Golden. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Director of Customer Financial Operations. In that capacity, I am responsible for Customer Financial Operations (Billing, Payment Processing, Revenue Management, and Universal Services).

3. Q. Please describe your educational background.

A. I have a Bachelor of Science in Business Administration from Drexel University and a Master of Business Administration from La Salle University.

4. Q. Please describe your professional experience.

A. I began my career with PECO in 1981 as a customer service representative. Between 1981 and 2000, I held positions of increasing responsibility in several departments including customer operations, large customer accounts, Gas Supply and Transportation ("GS&T"), Energy Acquisition, and Finance. My immediate past position was in Regulatory Policy and Strategy as the Director of Strategy. In September 2022, I became the Director of Customer Financial Operations at PECO.

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

A. The purpose of my testimony is to describe: (1) PECO's proposal for the recovery of Customer Assistance Program ("CAP") costs; (2) PECO's existing universal service programs in addition to CAP; (3) PECO's proposed revisions to its Matching Energy Assistance Fund ("MEAF"); and (4) PECO's proposal to expand outreach and education plans to better serve and reach low-to-moderate income ("LMI") customers.

II. RECOVERY OF CUSTOMER ASSISTANCE PROGRAM ("CAP") COSTS

6. Q. Ms. Golden, please describe PECO's current CAP for electric customers.

A. In accordance with the universal service obligations set forth in the Public Utility Code, PECO's CAP assists low-income customers in its service territory through discounted energy bills. PECO's CAP is a special rate rider for customers with an annual household gross income level at or below 150% of the federal poverty level ("FPL") as established by the US Department of Health and Human Services. As of December 31, 2023, approximately 123,000 residential electric customers in PECO's service territory – around 8% of PECO residential electric customers – were participating in CAP.

The structure of PECO's CAP discount has evolved over time. Most recently, in December 2022, PECO implemented a new CAP Percentage of Income Payment Plan ("PIPP"), approved by the Commission in Docket No. M-2018-3005795, to

provide a percentage of income-based benefit to CAP customers.[1] The PIPP design provides eligible customers with a fixed maximum monthly bill equal to what the CAP customer can afford to pay for utility service. The fixed bill amount is determined by applying an energy burden percentage[2] to the customer's annual income. CAP bill credits are applied to reduce the customer's monthly undiscounted bill to the monthly PIPP bill amount. For billing purposes, PECO applies the lesser of the CAP PIPP bill or actual charges. Bills issued under the CAP PIPP are subject to monthly minimum bill amounts and annual maximum credit amounts based on income level and electric rate.

Prior to employing a PIPP design, the Company utilized a Fixed Credit Option ("FCO") design (from October 2016 to December 2022) and a tiered rate discount CAP structure (prior to October 2016).

7. Q. What was the dollar amount of the aggregate PIPP bill credits provided to CAP customers in 2023 and how were those costs recovered?

A. The value of the CAP bill credits provided to low-income customers through PECO's electric CAP was approximately $140.7 million in 2023. These costs are recovered through a combination of base rates and a surcharge mechanism under Section 1307 of the Public Utility Code. In the settlement of PECO's 2010 electric base rate case ("2010 Settlement"), the parties agreed that PECO's base

[1] *PECO Energy Co. Universal Serv. and Energy Conservation Plan for 2019-2024 Submitted in Compliance with 52 Pa. Code §§ 54.74 and 62.4*., Docket No. M-2018-3005795 (Opinion and Order entered June 16, 2022) ("USECP Order").

[2] The energy burden percentage is the target percentage of household income that may be utilized to pay for utility service. Energy burden percentages vary based on the commodity (electric, electric heat, and gas) and household income level/number of residents.

rates would reflect recovery of $80.7 million for the costs of providing CAP bill credits to low-income customers.[3] Since that time, PECO has implemented several CAP enhancements to provide more affordable monthly bills to low-income customers based on the Commission's energy burden levels set forth in its CAP Policy Statement, which have caused the cost of the CAP program to increase substantially.[4]

The CAP "shortfall" refers to the amount of aggregate bill credits (in dollars) provided to CAP customers each year that is not reflected in base rates. This shortfall is recovered from or refunded to PECO's residential customers on an ongoing basis through PECO's Universal Service Fund Charge ("USFC"), with annual reconciliation of any over/under collections. Pursuant to the Commission-approved settlement of PECO's first default service proceeding (the "DSP Settlement"), the USFC is adjusted so that residential customers pay 73% of the total CAP shortfall amount.[5] The remaining 27% of the CAP shortfall is absorbed by PECO to account for the estimated impact to PECO's uncollectible expense (22%) and cash working capital requirements (5%). At that time, the 27% factor was associated with CAP program enhancements agreed to in the DSP Settlement, which

[3] *See Pa. P.U.C. v. PECO Energy Co. – Elec. Div.*, Docket No. R-2010-2161575 (Order entered Dec. 21, 2010), p. 10. In subsequent base rate cases, PECO increased the negotiated amount established in the 2010 settlement by the overall percentage of distribution revenue increase approved by the Commission. As such, PECO currently recovers approximately $86 million of CAP costs through base rates each year.

[4] 52 Pa. Code §§ 69.261–69.267.

[5] *See Petition of PECO Energy Co. for Approval of Its Default Serv. Program and Rate Mitigation Plan*, Docket No. P-2008-2062739 (Order entered June 2, 2009).

would be implemented at the same time as base rates established in PECO's 2010 electric rate case.

8. Q. Is PECO proposing to increase the amount of electric CAP bill credits included in its base rates in this proceeding?

A. Yes. The Commission's CAP Policy Statement was amended effective March 21, 2020, which, among other things, established lower recommended maximum energy burden targets for electric and gas CAP bills.[6] In accordance with the USECP Order, PECO's energy burdens were updated in late July 2022. As previously noted, in December 2022, PECO implemented its PIPP – providing eligible customers with a maximum monthly bill amount that is determined by applying an energy burden percentage to the customer's annual income. These two changes greatly increased the value of the bill credits provided to CAP customers.

In the fully projected future test year ("FPFTY"), the total estimated amount of PIPP bill credits for customers projected to be enrolled in CAP as of December 31, 2025 will be approximately $145.2 million. As explained by Company witness Joseph A. Bisti in PECO Statement No. 7, PECO proposes to update its base rate recovery to reflect this amount. Annual reconciliation of any over/under collections will continue to be via the USFC.

[6] *See Universal Service Rulemaking*, Docket No. M-2019-3012599 (Final Policy Statement Order and Annex entered on Nov. 5, 2019); 50 Pa.B. 1652 (Mar. 21, 2020).

9. Q. Ms. Golden, is PECO proposing to change the 27% offset percentage applied to the CAP shortfall, which is recovered through the USFC?

A. Yes. PECO proposes to change the offset factor applied to reconcilable CAP costs recovered through the USFC from 27% to 10.5%. When additional low-income customers enroll in CAP, PECO is more likely to recover at least a portion of the costs attributable to those customers because those costs will be collected from all residential customers through the USFC. PECO currently applies a 22% offset factor to reconcilable CAP costs in the USFC formula to reflect uncollectible expense increases or savings associated with incremental changes in the level of CAP bill credits embedded in PECO's base rates. PECO also applies a 5% USFC offset factor for cash working capital.

In light of the increase in value of CAP bill credits provided under the Company's PIPP, PECO has evaluated its recent uncollectible trends for CAP and all residential non-CAP customers to assess the remaining potential improvement in charge-offs. Based on that analysis, PECO is proposing to lower the uncollectible offset percentage to 5.5%.[7]

As explained by Company witness Michael J. Trzaska in PECO Statement No. 3, PECO calculated its claim for uncollectible accounts expense using a three-year historic average ratio of net charge-offs as a percentage of billed revenues. As shown in the table below, the uncollectible accounts rate for CAP customers was

[7] The Company is not proposing to change the 5% USFC offset factor applied to working capital requirements in this case.

calculated in the same manner by using the Company's actual charge-off experience for 2021 through 2023 divided by PECO's total billed revenues for the same three years. The offset percentage of 5.5% represents the difference between the uncollectible accounts rate for CAP customers (6.6%) and all residential non-CAP customers (1.1%).

	CAP Customer Billings vs Net Charge-Offs				All Residential Non-CAP Customer Billings vs Net Charge-Offs			
	2021	2022	2023		2021	2022	2023	
Annual Billings ($M)	$109.3	$118.7	$94.3	3-Year Average	$2,387.2	$2,861.1	$2,868.7	3-Year Average
Net Charge-Offs ($M)*	$3.3	$10.3	$7.7		$22.9	$28.9	$34.2	
Ratio (%)	3.0%	8.7%	8.2%	**6.6%**	1.0%	1.0%	1.2%	**1.1%**

*Excludes October 2016 one-time In-Program Arrearage ("InPA") forgiveness and Pre-Program Arrearage ("PPA") forgiveness.

III. OTHER UNIVERSAL SERVICE PROGRAMS

10. Q. What other types of universal service programs does PECO offer or administer to support the Company's low-income customers?

A. In addition to ongoing bill payment assistance through CAP, PECO provides usage reduction services via its Low-Income Usage Reduction Program ("LIURP"). LIURP is designed to complement CAP by providing usage reduction education and, if eligible, remediation measures to decrease the amount of energy used by customers, thereby reducing their bills and increasing affordability.

PECO also supports the Low-Income Home Energy Assistance Program ("LIHEAP"), a Federally-funded grant program that provides supplemental payments to eligible customers' accounts. PECO conducts extensive outreach and education regarding LIHEAP and provides support for customers seeking LIHEAP

grants. The LIHEAP application is available in English and Spanish on PECO's website, and the Company operates a LIHEAP hotline to assist customers with LIHEAP questions. Additionally, for LIHEAP Crisis customers who have a balance after the LIHEAP Crisis grant is applied to the bill, PECO offers payment agreements for the remaining balance. Finally, PECO targets LIHEAP customers for other assistance programs that may be available.

PECO has a Customer Assistance Referral and Evaluation Service ("CARES") team that provides referral and information services to assist special-needs, low-income customers who have financial hardships.

PECO also has a hardship program – MEAF – that provides customers at or below 200% of the FPL whose service is in threat of termination or has been terminated for non-payment with a grant to cure arrears. As discussed below, PECO is proposing a modification to its MEAF program as part of this filing to allow more customers to qualify for these grants.[8]

In addition to these universal service programs, PECO offers low-income customers no-cost energy assessments and direct installation of energy savings measures through the Company's Act 129 Energy Efficiency and Conservation Plan.[9]

[8] PECO notes that MEAF is a combined program for gas and electric customers. Changes to MEAF approved in this proceeding would apply to both gas and electric customers. The Company has made an identical MEAF proposal in its gas base rate filing at Docket No. R-2024-3046932.

[9] *See* Docket No. M-2015-2515691.

IV. REVISIONS TO THE MATCHING ENERGY ASSISTANCE FUND

11. Q. Please describe the MEAF established by PECO.

A. MEAF is a hardship program funded through donations[10] and matching PECO shareholder contributions. The program is administered in coordination with local community-based organizations ("CBOs") in each of the counties within the Company's service territory. The maximum MEAF grant is five hundred dollars ($500) per commodity (electric or gas). If the grant amount does not bring the account balance to zero, the customer will be required to make a payment and/or obtain other third-party funding (e.g., LIHEAP) to satisfy the remaining total amount due before being approved to receive the MEAF grant.

12. Q. What are the eligibility requirements for a MEAF grant?

A. PECO residential customers who apply for MEAF assistance are approved[11] if they:

- Have income at or below 200% of the FPL as defined by US Department of Health and Human Services ("HHS");
- Demonstrate hardship (i.e. service is in imminent danger of termination or has already been terminated);
- Reside within the county where they are applying for a MEAF grant;
- Have not received a MEAF grant in the past 12 months; and
- Have an account balance that would be brought down to zero with the MEAF distribution (note: this requirement can be met via a combination of MEAF grant, customer co-payments, and/or other grants).

[10] Customers or interested parties can pledge donations through bill payments or the PECO website. Donations can be either one-time or recurring, which can be charged via the customer's bill on a monthly basis.

[11] MEAF funds are distributed on a first-come, first-serve basis until exhausted.

13. Q. Could you please quantify the value of MEAF grants awarded in 2021-2023?

A. The value of MEAF grants varied yearly and ranged from approximately $80,000 to $250,000 (including the PECO shareholder match) for this period. In accordance with the Settlement in PECO's 2022 gas base rate case, PECO guaranteed to provide shareholder funding for MEAF grants of up to $300,000 annually, regardless of the amount of customer donations in a given year.[12] For the year of 2023, PECO matched $90,000 and provided the remaining balance of $210,000 to the MEAF agencies as additional grant funding available for 2024. PECO notes that this $210,000 is eligible to be matched by PECO in 2024.

14. Q. Is the Company proposing any modifications to its MEAF program as part of this rate case?

A. Yes. To expand the impact of MEAF and the number of customers eligible for the program, PECO is proposing to change the maximum allowable MEAF grant from $500 per commodity to $1,000 per account. This change should allow additional customers to meet the MEAF eligibility criteria of bringing the customer's account balance to zero by permitting all eligible customers (regardless of service type) to qualify for a MEAF grant of up to $1,000.

[12] Consistent with the Commission-approved settlement of PECO's 2022 gas base rate case at Docket No. R-2022-3031113 ("2022 PECO Gas Rate Case"), at the end of each program year, PECO allocates any funds for which it has not received a customer match – up to $300,000 annually – to the MEAF agencies in proportion to the number of low-income customers in each county within PECO's service territory.

V. EXPANDED CUSTOMER OUTREACH AND EDUCATION

15. Q. Please describe PECO's expanded customer outreach and education proposal.

A. The Company is looking to build upon existing outreach efforts and increase virtual enrollment opportunities for a range of residential customer offerings available to LMI customers. Specifically, the Company plans to expand its communications and marketing approach to increase customer awareness of universal service offerings, grant programs, and items such as budget billing, payment arrangements, medical certificates, and additional protections for victims of domestic violence. Actions will include expanded frequency of news releases and "pitching" of news media, more frequent social media posting, soliciting and working referrals from social workers and social service organizations, as well as additional targeted outreach to LMI customers.

16. Q. Does PECO already have an outreach budget for universal service programs?

A. Yes. As part of PECO's Commission-approved 2018-2028 Universal Service and Energy Conservation Plan[13] ("USECP"), the Company has an annual outreach and advertising budget of approximately $290,000 (electric and gas). Further, in PECO's last electric base rate proceeding (Docket No. R-2021-3024601), the Company was authorized to spend up to $500,000 each year on universal service program education and outreach. PECO tracks these incremental expenditures

[13] *See* Docket No. M-2018-3005795.

separately from USECP spending, and the costs are recovered from residential customers through the Company's existing Consumer Education Charge ("CEC").

17. Q. Did PECO fully utilize its authorized outreach budgets in 2022 and 2023?

A. The Company expended its entire $290,000 annual USECP budget in both years and expended $496,000 and $500,000 of the Company's expanded outreach budget in 2022 and 2023, respectively.

18. Q. Why does PECO believe that additional outreach funding is necessary?

A. The key drivers of the need for additional funding are: (1) connecting more eligible customers with LIHEAP funds; (2) ramping up virtual enrollment activities for universal service programs; and (3) accommodating an increase in customer referrals that is tied to the Company's outreach efforts.

Statewide, there is a substantial gap between the number of households that are eligible for LIHEAP and the number of households that receive LIHEAP. In 2021, for example, 1,538,208 households across the state were eligible for LIHEAP while only 303,500 received LIHEAP.[14] PECO primarily uses traditional channels, such as radio advertisements and mailing campaigns to former LIHEAP recipients and other low-income customers who should be eligible for LIHEAP grants, to encourage customers to apply for LIHEAP. With additional funding, PECO would increase the use of radio advertisement, social media, and other innovative means (i.e., virtual enrollments) to educate low-income customers and increase their awareness of LIHEAP and how to apply.

[14] https://neuac.org/wp-content/uploads/2023/07/Pennsylvania-State-Sheet-FY2024.pdf.

Virtual enrollment activities can connect PECO customers in need with a range of assistance, including CAP, LIHEAP, and other residential customer offerings such as budget billing. The Company utilizes targeted emails, social media, and customer outreach events to solicit customer participation in the sessions. PECO began to host virtual enrollment sessions in 2022 and in 2023 conducted over 20 sessions assisting 650 customers. In addition, customers that did not attend their virtual enrollment appointment received a follow up call the next business day to facilitate enrollment in appropriate programs. With additional funding, PECO would increase the frequency of virtual events.

Finally, PECO's expanding community outreach efforts are leading to individual customer referrals from a variety of external partners, including hospitals. Referrals are typically for universal service programs, such as CAP, LIHEAP and MEAF. PECO began formally tracking referrals in 2023 and received over 1,600 referrals from numerous organizations (e.g., Findhelp, Thomas Jefferson Hospital System, and elected officials' offices). PECO expects that expanded outreach will drive additional referrals and that additional funding will be required to appropriately address an increasing number of referrals.

19. Q. What level of additional funding is PECO requesting in this case and how would costs be recovered?

A. PECO is requesting a $300,000 increase to the $500,000 annual expanded outreach budget that was approved by the Commission in PECO's 2021 electric base rate proceeding, for a total of $800,000 annually. This increased funding would be recovered through the Company's existing CEC.

VI. CONCLUSION

20. Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

PECO ENERGY COMPANY
STATEMENT NO. 10-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

REBUTTAL TESTIMONY

WITNESS: JAQUELINE F. GOLDEN

SUBJECT: LOW-INCOME CUSTOMER ISSUES; RECOVERY OF CUSTOMER ASSISTANCE PROGRAM COSTS; RESIDENTIAL CUSTOMER ISSUES; CUSTOMER SERVICE AND BILLING ISSUES

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
JAQUELINE F. GOLDEN

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Jacqueline F. Golden. I am employed by PECO Energy Company ("PECO" or the "Company") as the Director of Customer Financial Operations. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct testimony marked as PECO Statement No. 10. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will address the following topics raised by other parties in direct testimony.

Low-Income Customer Issues: I will respond to the direct testimony of Elizabeth R. Marx on behalf of the Tenant Union Representative Network ("TURN") and the Coalition for Affordability Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") (collectively "TURN/CAUSE-PA"), the direct testimony of Mr. Roger Colton on behalf of the Office of Consumer Advocate ("OCA"), and the direct testimony of Elizabeth H. Lankenau on behalf of the City of Philadelphia and the Philadelphia Energy Authority (collectively, "City/PEA") concerning bill affordability, the definition of "confirmed low-

income customer", customer noticing regarding PECO's Customer Assistance Program ("CAP"), the use of speech analytics software, security deposit policies, and proposed changes to several of the Company's Universal Service programs.

Universal Service Fund Charge ("USFC") Offset Factors Costs: I will respond to Mr. Colton's testimony concerning the bad debt offset factor in the USFC formula.

Residential Customer Issues: I will respond to Mr. Colton's and Ms. Marx's proposals concerning language access, methodologies used for security deposits and termination scheduling, customer touchpoints regarding Rate R / Rate RH designation, and the application of customer payments to dual customer bills. I will also address Mr. Colton's contention that PECO is not providing exemplary service in the areas of Universal Service, credit and collections.

Customer Service Issues: With respect to large customer account management and billing issues, I will respond to the direct testimony of James L. Crist on behalf of the Southeastern Pennsylvania Transportation Authority ("SEPTA"), as well as the direct testimony of Dominic G. McGraw on behalf of the City/PEA. I will also address direct testimony provided by OCA witness Nicolas A. DeMarco regarding customer service and satisfaction, call center performance and billing matters. I also note the supportive direct testimony provided by Lisa V. Perry on behalf of Walmart, Inc.

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

A. Yes, I have prepared PECO Exhibit JFG-1 which I describe later in my testimony.

II. LOW-INCOME CUSTOMER ISSUES

5. Q. Ms. Marx, Mr. Colton and Ms. Lankenau each emphasize concerns about affordability for low-income customers in response to the Company's proposed base rate increase. Please describe the Company's existing efforts and proposal in this proceeding to connect customers in need with programs that can reduce their bill.

A. PECO has a robust Community Education and Outreach Plan ("CEOP") to facilitate customer awareness of and connection to assistance programs, along with enrollment in, the Company's Universal Services offerings. The CEOP is filed with the Commission, shared with PECO's Universal Services Advisory Committee ("USAC"), and updated on an annual basis. PECO conducts hundreds of outreach events in coordination with community-based organizations throughout the Company's service territory every year and utilizes both U.S. Census (zip code data for low-income and limited English proficiency "LEP" areas) and PECO customer data (zip codes with the highest termination rates) to determine event locations. When an event is focused on an LEP community, the Company provides interpretation services. PECO also partners with dozens of social service agencies by providing them with Universal Services materials and educating their staff (as well as customers) about important concepts such as income eligibility (i.e., how to read and interpret the Federal Poverty Level ("FPL") chart). PECO also sends CAP-specific mailings and conducts outbound calls to confirmed low-income customers and non-CAP recipients of Low-Income Home Energy Assistance Program ("LIHEAP") grants to encourage them to apply to CAP and provide instructions on how to apply. Additionally, the Company

provides all new residential customers with a welcome packet which includes information on assistance services, such as CAP, the Matching Energy Assistance Fund ("MEAF"), the Low-Income Usage Reduction Program ("LIURP"), the Customer Assistance Referral and Evaluation Service ("CARES") and LIHEAP.

The Company has further integrated virtual outreach and enrollment activities and extensive programmatic information on its website (peco.com/help) to expand the ways in which customers can learn about assistance programs. This information is available on PECO's website in Spanish and Simplified Chinese. PECO has also implemented the Assistance Finder tool on PECO's website, which provides customers with access to information on financial assistance, bill management, and saving money and energy (e.g., PECO's Universal Services programs). In fact, from May 2023 through April 2024, almost 40,000 customers completed the survey in the tool and received personalized program recommendations along with nearly 5,000 customers submitting CAP applications. In addition, PECO monitors its education and outreach performance by tracking a variety of metrics, including some specific to activities for customers at or below 50% of the FPL as noted in the Company's 2024 CEOP filing.

The Company will continue these efforts and provide further enhanced outreach services with the incremental request of $300,000 proposed in my direct testimony. The additional funding will build upon existing efforts and enable PECO to: (1) connect more eligible customers with LIHEAP funds; (2) ramp up virtual enrollment activities for Universal Service programs; and (3)

accommodate an increase in customer referrals that is tied to the Company's outreach efforts.

6. Q. Ms. Marx and Mr. Colton each contend that PECO's definition of a "confirmed low-income customer" is not consistent with PUC regulations and recommend that PECO's tariff and policies reflect a definition that includes, among other things, customers who self-certify income without additional documentation. Please respond.

A. I disagree that PECO's definition of a "confirmed low-income customer" is inconsistent with PUC regulations. PECO defines "confirmed low-income" as customers who, in the last two years, have provided verified financial information (i.e., proof of income documentation) at or below 150% of FPL, and/or enrolled in CAP, and/or received a LIHEAP grant. This description is consistent with electric and gas regulatory definitions of "confirmed low-income residential account" which both refer to a utility obtaining "information that would reasonably place the customer in a low-income designation."[1] Utilities are not required to accept self-certification without additional documentation.[2]

7. Q. Mr. Colton recommends that PECO utilize speech analytics software to assist with the quality monitoring of calls involving, or potentially involving, Universal Service programs and other low-income customer issues. He further recommends that PECO involve its USAC in terminology selection

[1] 52 Pa. Code 54.72 (electric); 52 Pa. Code 62.2 (gas).

[2] The regulatory definition applicable to Natural Gas Distribution Companies ("NGDCs") at 52 Pa. Code §62.2 identifies self-certification as a type of information a NGDC *may* accept.

and report on monitoring results to the USAC. Please respond.

A. PECO's call center employs a natural language processing analytics solution to help the Company better understand reasons for calls and identify opportunities to improve processes and customer service representative performance. The Company currently uses this analytics solution to identify calls on current news publications, price impact on customer sentiment, system changes, and whether a customer may be having technical issues. PECO is open to sharing common search terms with the USAC.

8. Q. Please summarize Ms. Marx's recommendations concerning the collection and refund of security deposits from low-income customers.

A. Ms. Marx recommends that PECO: (1) educate customers about the low-income security deposit exemption and income screening customers prior to assessing a security deposit; (2) within 30 days of final order in this proceeding, review all prior security deposit collection from low-income customers, issue refunds and continue the monthly review moving forward; and (3) issue refunds as appropriate directly to customer, with account credits used only if the customer consents.

9. Q. Do you support the implementation of those proposals?

A. No. By way of background, I would like to explain the Company's processes with respect to low-income customers and security deposits.

When a new residential customer requests a connection for service, a deposit will be assessed based on the information provided by a third party vendor, whether the customer has limited or no credit history, or if the customer has a prior written off or "finaled" delinquent PECO account. If the customer says that they cannot

pay the assessed deposit, PECO informs the customer that PECO will send a letter with contact information that the customer can use to call and speak to a Company representative regarding the customer's income information and request to waive the deposit after verifying their low-income eligibility for such a waiver. Customers who are verified low-to-moderate income ("LMI") $\leq$ 250% of FPL are excluded from being assessed a deposit.

PECO also reviews existing accounts to determine if a deposit may be required depending on where a customer may be in the collections process. Typically, a deposit is required if the customer meets the following criteria:

- There is not already a deposit assessed on the account;
- Late payment charges have been applied three times in the prior 12 months; and
- The account has received a deposit warning in the prior four months

If the first two conditions are met, but the third is not, PECO will send a deposit warning, rather than assess a deposit. In this instance, customers who are verified LMI $\leq$ 250% of FPL are also excluded from being assessed a deposit.

PECO also regularly reviews residential accounts to ensure that deposits have been properly assessed. If a customer paid a deposit and becomes a verified LMI customer subsequent to paying the deposit, PECO will apply the deposit to the customer's account to reduce the amounts they would otherwise owe. If a customer who does not need to maintain a deposit contacts PECO to request a cash refund of a security deposit credit, PECO will issue a check in the amount of any excess credit on the customer's account.

In sum, customers who are determined to require a deposit are excused from deposit obligations upon income verification, with credits or refunds available where appropriate. I do not believe there is any reason to change PECO's existing security deposit procedures.

A. Customer Assistance Program

10. Q. Please summarize Ms. Marx's recommendations concerning CAP enrollment processes.

A. Ms. Marx makes several enrollment-related recommendations, including: (1) participation by PECO in the Department of Human Services ("DHS") data sharing program; (2) routine Universal Services screening for new, moving and non-emergency calls, including a warm transfer process if necessary; and (3) automatically enrolling or recertifying customers following receipt of a LIHEAP grant, which could include an "opt-out" component.

11. Q. Do you agree with Ms. Marx's proposals?

A. The Company is actively considering participation in the DHS data sharing program and, if the Company elects to participate, it will file a letter by July 31, 2024 as directed by the Commission.[3] The Company disagrees, however, with the proposal concerning routine screening. If a customer calls to discuss a past due balance, identifies affordability concerns, or asks about Universal Services programs, the Company already asks about income status to screen for potential CAP eligibility, establish payment arrangement terms, and advise of other

[3] *2023 Review of All Jurisdictional Fixed Utilities' Universal Service Programs*, Docket No. M-2023-3038944 (Order entered June 13, 2024).

assistance programs and external grant programs available. PECO does not agree that it would be appropriate to ask all customers about their income during all other types of non-emergency customer service calls (e.g., moving to a new service address) given that the purpose of the customer's call was not related to affordability or assistance programs and the Company would be requesting information that the customer may not be comfortable providing.

Regarding enrollment processes, the Company disagrees with the proposals on automatic enrollment. PECO believes customers should maintain the ability to affirmatively choose whether or not to enroll in CAP or participate in any other low-income program. While auto-enrollment may offer benefits to a customer in the form of bill discounts, it may also restrict other types of customer activities. For example, if a PECO customer is enrolled in CAP they cannot shop for an electric supplier, utilize budget billing, or retain their one-time opportunity for Pre-Program Arrearages ("PPA") forgiveness if they do not currently have a significant past-due balance. Furthermore, customers should have the opportunity to understand the specific program benefits and requirements before being enrolled in CAP.

Additionally, while the Commission has encouraged utilities to consider implementation of auto-enrollment of LIHEAP recipients into CAP, PECO believes that in addition to customers maintaining their right to affirmatively choose whether or not to enroll in CAP, it is important to consider the increased costs to all residential customers, including CAP and non-CAP LMI, of auto-enrollment. In 2023, PECO received LIHEAP grants for approximately 10,000

non-CAP customers. Using the forecasted 2025 average annual CAP bill credit of approximately $1,200,[4] auto-enrolling these customers in CAP would increase bill credits by up to $12 million. Additional enrollments of future non-CAP LIHEAP recipients would further increase bill credit costs. And while Ms. Marx proposes an "opt-out" option (i.e., auto-enrollment occurs unless a customer affirmatively chooses to "opt out" of any auto-enrollment), such an approach can be expected to also result in higher cost associated with CAP back office administration, PIPP correspondence mailings, and Information Technology ("IT") implementation costs.

In addition, regarding recertification, PECO's Universal Service and Energy Conservation Plan ("USECP") already provides for an extended recertification cycle for LIHEAP recipients. Specifically, CAP customers who receive LIHEAP grants may recertify on a four-year cycle instead of the standard two-year cycle. Finally, as described in more detail in PECO's USECP, if a customer is removed from CAP and then re-enrolls within the following 12-month period, the customer is entitled to receive credits reflecting the CAP bill credits they would have received if they were enrolled during that period.

12. Q. Please summarize Mr. Colton's proposals concerning additional customer contacts during disconnection and reconnection related to CAP.

A. Mr. Colton recommends that PECO make personal contact with a confirmed low-income customer prior to disconnection to offer the opportunity to apply for CAP

[4] The Company is forecasting an average annual CAP bill credit of $1,216 in 2025 (2025 total CAP credit forecast of $159.2 million divided by the 2025 average CAP enrollment forecast of 130,875).

and the associated arrearage forgiveness. If the customer expresses a desire to apply, Mr. Colton proposes that PECO postpone the disconnection for a reasonable period of time to allow the CAP application process to be completed. When a confirmed low-income customer is being reconnected, Mr. Colton proposes that the customer be required to affirmatively acknowledge that they do not wish to participate in CAP (along with its arrearage forgiveness program) prior to being reconnected and required to pay either a portion of their outstanding arrears or any reconnection fee.

13. Q. Do you agree with his proposals?

A. No, PECO's existing termination noticing process already provides customers with appropriate information about the availability of assistance programs as well as how to contact the Company about other customer protections that may prevent termination. PECO's terminations of service are performed consistent with Commission regulations and include repeated notices for each customer. A customer at risk for termination of service first receives a 10-day notice, which includes specific information on contacting PECO, availability of assistance programs, and rights a customer may have to continue service. A customer who receives this notice and then contacts a PECO customer service representative ("CSR") will be granted a 10-day collections hold following any credit call with the CSR that does not result in taking the customer out of collections. Likewise, a 10-day collections hold will be granted by the Interactive Voice Response ("IVR") when a customer seeks to use the minimum payment option or to enter into a deferred payment agreement but is unsuccessful in doing so. This permits

the customer time to provide proof of income to enroll in CAP, make a payment, or request a payment arrangement if eligible.

If a customer still does not take action, PECO attempts to directly contact the customer 72 hours prior to termination through calls or direct contact by leaving a physical notice at the property, again with information that they may be eligible for available assistance and customer rights. When a customer calls PECO to make a payment to avoid termination or to reconnect, the CSR will explore options with the customer, which may include taking an income statement to confirm eligibility for longer payment arrangement terms and providing information about Universal Services program enrollment.

If a customer expresses the desire to apply for CAP, the customer is provided with instructions on how to access the online portal and/or pdf application. If the customer requests a paper copy, they are mailed a CAP application. CAP applications can be submitted via mail, email, fax or the online portal, and as previously stated the customer has ample time to apply once the 10-day hold is placed on their account.

If termination does occur, the customer is provided with yet another notice of the steps they can take to restore service. If the customer demonstrates that they are confirmed low-income and are a first time CAP customer, they may be eligible for restoration with the full balance to be set aside under PECO's PPA forgiveness program. In sum, during pre- and post- termination calls, if a CSR determines that a customer may be low-income based on the information the customer provides on the call, the CSR will provide information on Universal

Services programs including CAP and the discussions with the customer, including the customers decisions, are noted on their account.

14. Q. Please summarize Mr. Colton's proposals concerning "stand alone" noticing related to CAP.

A. Mr. Colton recommends that PECO provide stand-alone notices concerning CAP and associated arrearage forgiveness in the following situations: (1) when a customer is found to be without heating during cold weather survey; (2) when negotiating a deferred payment agreement with a confirmed low-income customer or a customer where information is generated during the payment arrangement process to place them in the Tier I income range (at or below 150% of FPL); (3) when a confirmed low-income customer has accrued an unpaid balance of $300 or more; and (4) when requesting a cash security deposit from a confirmed low-income customer.

15. Q. Do you agree with his proposals?

A. No, PECO's existing processes already provide customers with appropriate information about CAP and other Universal Services programs. First, customers identified through the winter survey process already receive a range of materials from the Company, including a CAP Application, Universal Services Program Information Sheet, and a LIHEAP Application during LIHEAP season. Second, when a Tier 1 confirmed low-income customer is negotiating a deferred payment arrangement, they are provided information about CAP and how to apply. Third, confirmed low-income customers routinely receive information about CAP,

regardless of their unpaid balance, and how they can enroll, including automatic mailings of CAP applications to non-CAP LIHEAP recipients.

Further, PECO conducts annual CAP outreach via direct dialed phone calls in May and U.S. mailing in October to confirmed and unconfirmed low-income[5] non-CAP customers, regardless of whether they have an unpaid balance. Customers with an unpaid balance also receive information about assistance programs and the multiple pre-disconnection notices and contacts as described earlier in my rebuttal testimony. Finally, with regard to security deposits, and as discussed above, customers who are verified LMI ≤ 250% of FPL are excluded from being assessed a deposit.

16. Q. Please summarize Ms. Marx's recommendations concerning maximum CAP credits.

A. Ms. Marx argues that PECO should recognize all maximum credit exemptions identified in the Commission's CAP Policy Statement. She further recommends that PECO notify customers earlier that they are approaching their maximum credit and that the notification letter include information about when the maximum credit will expire, how to access LIURP, and information for Rate R customers that may be using electric heating. Finally, Ms. Marx recommends that PECO evaluate all households reaching the max credit by the eleventh month or earlier for LIURP and adjust the max CAP credit amounts with adjustments in the Price-to-Compare ("PTC").

[5] An unconfirmed low-income customer is a customer that has provided a verbal statement of income but has not provided physical documentation of income.

17. Q. Do you agree with Ms. Marx's proposal to recognize additional exemptions to the maximum CAP credits?

A. No. As an initial matter, the CAP Policy Statement (52 Pa. Code § 69.265 (3)(vi)) states that a utility *may* exempt a household from CAP credit or consumption limits if one or more of the following conditions exists: (1) addition of a household member; (2) serious illness of a household member; (3) energy consumption beyond the household's ability to control; (4) housing that is condemned or has housing code violations that negatively impact energy consumption; or (5) energy consumption estimates based on a previous occupant. PECO currently has a health usage rider in place to address the serious illness of a household member. Specifically, the health usage rider exempts a customer from maximum CAP credits when more than 100 kWh per month of electric consumption is needed for life sustaining equipment (e.g., an oxygen concentrator).

The Company does not believe that exemptions are warranted for the other four conditions listed in the CAP Policy Statement. First, if a customer experiences the addition of a household member, they can contact PECO to reverify their income and household size to determine if they qualify for a lower PIPP[6] amount and a potentially higher annual maximum CAP credit amount if their updated FPL places them in a lower FPL tier. Second, CAP customers with high usage can request to participate in PECO's LIURP program, its Energy Efficiency programs, Act 129 and Safe and Efficient Heating Program ("SEHP"), and/or apply for

[6] PECO's CAP is structured as a Percentage of Income Payment Plan or "PIPP."

LIHEAP. Even in the absence of a customer request, PECO transmits CAP customer information to its LIURP vendor on a monthly basis, including information about which customers have reached 75% or more of their maximum CAP credit, to assist the vendor with prioritizing high-usage customers. Third, PECO does not believe that housing code violations warrant unlimited CAP credit amounts. Housing conditions should be addressed primarily by the property owner, such as the landlord or customer. Finally, the exemption for consumption estimated based on a previous occupant does not apply to PECO's CAP. A customer's PIPP credits and annual maximum thresholds are based on current usage, rate, and FPL, not estimates of a previous occupant's energy consumption.

18. Q. Do you support Ms. Marx's proposals to change the timing and content of the notification letter and to evaluate customers approaching their maximum credit for LIURP?

A. No. The timing of PECO's notification letters (at 75% and 90% of a customer's maximum credit) was approved by the Commission as part of PECO's USECP and the overall content of the letters was reviewed by the Commission's Bureau of Consumer Services. I also note that PECO could not accurately forecast exactly when a customer's annual maximum credit will expire because the value of a customer's PIPP credits vary from month to month based on factors such as weather and the customer's consumption behaviors.

Further, as explained above, PECO already directly provides its LIURP vendor with information about high usage CAP customers for review every month. Per the LIURP regulations, PECO's focus is on customers with the highest need

where LIURP assistance can maximize potential bill savings.[7] If a customer has used 75% of their available credits since their last annual maximum reset, that customer will have already been included in a list provided to the LIURP vendor for review.

19. Q. Do you agree with Ms. Marx's recommendation to adjust maximum CAP credits when the PTC is adjusted?

A. No. PECO's Commission-approved USECP already addresses how and when maximum CAP credits should be updated based on changes in distribution rates. PECO believes that Ms. Marx's proposal to adjust the maximum based on the PTC would create confusion for customers, be potentially detrimental to the customer, and result in increased costs associated with IT and process changes that would be needed to implement such a complex requirement. PECO currently updates the residential PTC four times per year. If Ms. Marx's proposal were implemented, a customer's maximum CAP credit amount would also change four times a year. This could make it difficult for a customer to understand their progress towards the maximum and plan financially for exceeding or remaining within their maximum. A quarterly adjustment would also add an additional layer of complexity for the Company if they were required to attempt to forecast when customers would reach their maximum, and require duplicative communications as customers may hit their 75% and/or 90% annual maximum limit multiple times within the same annual period.

[7] *See, e.g.,* 52 Pa. Code § 58.10(a)(1) (priority for receipt of program services is for eligible customers "with the largest usage and greatest opportunities for bill reductions relative to the cost of providing program services…").

20. Q. City/PEA witness Lankenau states that the City and others would benefit from "improved reporting" of Universal Services data and recommends that PECO initiate regular stakeholder meetings with the City and others to discuss data collection needs and the communication of data. Please respond.

A. As Ms. Lankenau acknowledges, PECO already reports a range of Universal Services program data to the Commission and PECO-specific information is available in a variety of PUC reports. PECO also conducts quarterly USAC meetings with its USAC members which include Utility Emergency Services Fund ("UESF") and Energy Coordinating Agency ("ECA"), both are organizations supporting our most vulnerable customers in the City of Philadelphia, providing grant support to customers having trouble paying their utility bills and supporting those customers seeking heating system repair, home weatherization to save energy, utility bill assistance, energy conservation education, and connections to a wide range of services across the City. At those meetings, PECO provides a detailed overview of assistance programs including CAP, LIHEAP, LIURP and MEAF performance, providing data on customers served, amounts spent on individual programs, and other metrics. Separately, PECO also engages with its USAC members to discuss issues of interest and communicate other key information. PECO does not believe that changes are needed to its dual tracks of formal reporting and responding to informal inquiries of stakeholders.

21. Q. City/PEA witness Schapira expresses concern that participation in the City's "Solar for All" program may conflict with mutually participating in CAP.

Please respond.

A. PECO customers may simultaneously participate in CAP and "Solar for All." PECO has been actively collaborating with PEA and others on the implementation of this program, including coordinating the program with PECO's Universal Service programs. If a CAP customer participates in "Solar for All," and either owns or leases solar panels on their premise, they will receive an offset in their billed usage and will pay the lesser of their PIPP bill amount or the actual usage amount, subject to a minimum bill amount. The usage offset will benefit the CAP customer by reducing the PIPP credits applied each month and slowing the customer's utilization of their maximum annual CAP credit allotment.

B. <u>LIURP</u>

22. Q. Ms. Marx is critical of PECO's LIURP job completion rate, spending per job and service of tenants. She recommends that PECO: (1) increase its LIURP budget by $4,400,000 to about $10,000,000; (2) revise its high usage eligibility threshold to account for usage on a per square-foot basis; (3) improve direct solicitation to high usage CAP customers; and (4) provide reports to USAC about (i) barriers and solutions regarding tenant issues and (ii) barriers and solutions regarding coordination with other home repair and weatherization programs. Please respond.

A. At the outset, I would like to clarify that PECO's current electric LIURP budget is $6.6 million, so a $4.4 million increase would bring the total electric LIURP budget to $11 million. I further note that PECO is actively participating in the

Commission's LIURP Notice of Proposed Rulemaking ("NOPR") proceeding[8] and has filed comments regarding the Commission's efforts to update the LIURP regulations. To the extent Ms. Marx has programmatic LIURP recommendations, they would be more appropriately raised in the NOPR proceeding.

Turning to the specific criticisms, I disagree with Ms. Marx that the success of PECO's LIURP can be measured by looking at individual statistics in isolation. Each LIURP participant household is evaluated and measures are implemented if they meet LIURP requirements, including certain payback period requirements as defined in the LIURP regulations.[9] The spending per household is a function of what measures are appropriate in the homes we evaluate in a given year. The number of jobs completed in a year is also dependent upon a number of factors, including how many measures are being installed, and their costs, in each premise. We continue to focus on assisting high usage customers and installing measures that will maximize energy saving benefits.[10] Importantly, since the removal of COVID restrictions, PECO has been expending its full LIURP budget for the benefit of customers. Over the years we have consistently increased the LIURP budget and believe the current budget is appropriate. Just last year, the LIURP budget was increased by $1 million for electric service and $0.9 million for gas service. These increases, along with dedicated Health and Safety spending

[8] *See* Docket No. L-2016-2557886.

[9] *See, e.g.,* 52 Pa. Code § 58.11 (establishing payback periods applicable to LIURP measures).

[10] Notably, the energy savings resulting from LIURP jobs has increased significantly. The latest APPRISE LIURP Evaluation Final Report completed in 2024 for 2022 found that: (1) savings from electric heating jobs averaged 10.5%, compared to recent years that had savings below 6%; and (2) savings from gas heating jobs were 7.2% compared to recent years that were all below 5% and often below 3%. *See* PECO Exhibit JFG-1 for a copy of the APPRISE LIURP Evaluation Final Report.

($1.5 million for the permanent electric program and $100,000 for the gas pilot expiring at the end of 2025), brings PECO's LIURP spending to approximately $11.4 million annually.

Second, PECO does not have, and has no feasible way of collecting, the square footage of each customer premise in advance of a LIURP audit in order to deploy the type of usage per square-foot threshold recommended by Ms. Marx. PECO notes that Act 129 can provide electric energy efficiency support for low-income customers who reside in smaller dwellings and do not meet LIURP's usage threshold. Similarly, on the gas side, certain low-income customers with lower total usage but higher usage per square-foot can access no-cost measures through the SEHP. In addition, in response to Ms. Marx's comments on barriers to tenants, PECO does work with customers who are renters to minimize barriers. If a customer is a renter, the LIURP contractor will contract with the property owner and provide a consent form and self-addressed postage paid envelope. The contractor will follow-up for receipt of the consent form before the work begins. Consent from the owner can also be obtained verbally over the phone on a recorded line. A letter shall be delivered to the customer and property owner confirming that consent has been obtained.

Regarding the final recommendation about reporting to the USAC on various LIURP issues, PECO already appropriately engages the USAC and program partners. In addition to regularly sharing LIURP information, PECO conducted two multi-family collaboratives (one in 2022 and one in 2023) with a range of stakeholders, including the OCA, Community Legal Services, and the Public

Utility Law Project.[11] During the collaborative, the Company discussed how PECO could support all types of dwellings by utilizing LIURP and its energy efficiency and conservation ("EE&C") programs. PECO also collaborates with the PEA and its Built to Last Program ("BTL") by accepting direct referrals from BTL for PECO's Act 129 EE&C low-income programming. Eligible customers are scheduled for a free energy checkup and measures are provided to the customer at no cost.[12]

C. MEAF

23. Q. Ms. Marx recommends that: (1) MEAF grant amounts be increased to $1,000 for baseload electric service with an additional $1,000 for heating customers; (2) MEAF funds be distributed proportional to low-income populations in each county; and (3) PECO replace MEAF's zero balance requirement with a requirement that a grant be sufficient to "resolve the crisis." Do you agree with these recommendations?

A. I do not. PECO continues to believe that the Company's proposal to change the maximum allowable MEAF grant from $500 per commodity to $1,000 per account is appropriate. This change should allow additional customers to meet the MEAF eligibility criteria of bringing the customer's account balance to zero by permitting all eligible customers (regardless of service type) to qualify for a MEAF grant of up to $1,000. Fundamentally, the MEAF program is an

[11] The collaboratives were held in accordance with a Commission-approved settlement in PECO's most recent gas base rate proceeding (Docket No. R-2022-3031113).

[12] In discovery response cited by City/PEA witness Schapira (pp. 11-12), PECO interpreted "coordination" as PECO LIURP either working on the same project or paying for components of a BTL job as was requested during the BTL pilot.

emergency program to help customers avoid termination, and an increase in grants for higher balances will provide assistance to fewer people.

Regarding the distribution of MEAF funds, as I explained in my direct testimony, PECO already distributes any funds for which it has not received a customer match – up to $300,000 annually – to the MEAF agencies in proportion to the number of low-income customers in each county within PECO's service territory. The distribution of these remaining funds to the agencies then becomes available as a contribution for the agency to use as their portion of the grant, to be matched by an additional PECO shareholder contribution per the normal MEAF process, thereby increasing the funds available in the counties for future application to customer accounts. Finally, PECO does not believe the zero-balance requirement should be waived because MEAF is not intended to be a supplemental grant program, but rather a means to address collections risk by achieving a zero balance.

24. Q. Please summarize Ms. Marx's recommendations concerning MEAF grant availability and oversight of MEAF agencies.

A. Ms. Marx identified some grant issuance delays by PECO's MEAF agency in Philadelphia County – the UESF – and generally expressed concern about the number of grants issued and the underspending of available funds. She recommends that: (1) PECO monitor the performance of each MEAF agency including requiring monthly reports from each agency; (2) PECO file monthly reports on the status and availability of MEAF; and (3) MEAF operation issues be

referred to the Commission's Bureau of Audits and Bureau of Investigation and Enforcement.

25. Q. Do you agree with her recommendations?

A. I believe that PECO already has sufficient processes in place to monitor MEAF agency activity. On a weekly basis, PECO reviews MEAF grants received and posting of matching PECO shareholder contributions. On a monthly basis, PECO reviews invoices from MEAF agencies to track and confirm each agency's activity. PECO also hosts quarterly USAC meetings where MEAF agencies attend and have the opportunity to address issues and answer questions. The Company does not believe that MEAF implementation issues warrant investigation by the Commission because: (1) the Company's issues were temporary and have been resolved; (2) PECO has implemented continuous monitoring of UESF; and (3) PECO will affirmatively communicate significant issues with a MEAF agency to the Commission's Bureau of Consumer Services ("BCS") and provide them with status reports as appropriate.

III. OFFSET FACTORS IN THE UNIVERSAL SERVICE FUND CHARGE

26. Q. Have any parties opposed PECO's proposal to change the offset factor applied to reconcilable CAP costs recovered through the USFC from 27% to 10.5%?

A. Yes. Mr. Colton contends that PECO's proposal to lower the bad debt component of the USFC offset factor from 22% to 5.5% based on the difference between the three-year average (2021-2023) uncollectible rate for CAP customers and all residential customers artificially reduces the offset factor. Mr. Colton makes

some additional contentions regarding the cash working capital offset which are addressed in the rebuttal testimony of Mr. Trzaska.

27. Q. Does Mr. Colton dispute that the difference between the three-year average uncollectible rate for CAP customers and all residential customers is a reasonable methodology to determine the offset (positive or negative) to PECO's bad debt expense arising from incremental changes (increases or decreases) in CAP enrollment levels?

A. No. However, Mr. Colton contends that using 2021 in the three-year average is unreasonable since PECO's rate of net charge-offs was abnormally low in that year due to the impact of the COVID-19 pandemic on customer collections activities.

28. Q. Is PECO making any changes to its proposed update to the bad debt adjustment in the USFC formula to address Mr. Colton's concerns?

A. Yes. PECO proposes removing 2021 from the three-year average rate of net write offs in the calculation described in my direct testimony. As shown in Table 1 below, using a three-year average for calendar years 2019, 2022 and 2023 produces a bad debt offset percentage of 7.1%, which is 1.6% higher than PECO's original proposal.

Table 1

	CAP Customer Billings vs Net Charge-Offs				All Residential Customer Billings vs Net Charge-Offs			
	2019	2022	2023		2019	2022	2023	
Annual Billings ($M)	$102.0	$118.7	$94.3	3-Year Average	$2,331.4	$2,861.1	$2,868.7	3-Year Average
Net Charge-Offs ($M)*	$7.2	$10.3	$7.7		$14.8	$28.9	$34.2	
Ratio (%)	7.0%	8.7%	8.2%	**8.0%**	0.6%	1.0%	1.2%	**0.9%**

*Excludes October 2016 one-time In-Program Arrearage ("InPA") forgiveness and Pre-Program Arrearage ("PPA") forgiveness.

IV. RESIDENTIAL CUSTOMER ISSUES

29. Q. Mr. Colton contends that PECO has no claim for "exemplary management" in the area of (1) Universal Service and (2) credit and collections performance, citing CAP enrollment numbers and payment arrangement and disconnection statistics for low-income customers, and the level of residential arrears. He further argues that PECO does not appropriately query customer satisfaction or utilize technology to enable assistance with program enrollment. Please respond.

A. I believe we have provided extensive support for PECO's exemplary management performance. In light of Mr. Colton's testimony, however, I want to highlight several areas where we have provided substantial assistance to the low-income customers we serve.

- In July of 2022, PECO incorporated the updated energy burdens in the CAP Policy Statement and then converted the structure of its CAP to a PIPP in December 2022. Overall CAP bill credits to customers increased by approximately $27 million for electric and gas from 2021 to 2022. Additionally, in 2023, the first full year of the PIPP, CAP customer bill credits increased by approximately 64% for electric service (from $86 million in 2022 to $140.7 million) and more than 100% for gas service (from $5.3 million in 2022 to $10.9 million). While CAP enrollment varies throughout the year, it has remained relatively consistent over the last several years averaging approximately 122,000 customers since 2021. As evidenced by our CEOP, PECO is focused on outreach to customers

who are in need of financial support while also ensuring that customers enrolled in CAP remain eligible through requiring income recertification so that more program funds are available for those most vulnerable. In addition, as discussed earlier, PECO has recently increased its LIURP budgets.

- PECO's termination procedures and other credit and collection processes are applied equally to all customers and PECO does not target specific zip codes or classes of individuals. PECO's credit and collections activities are focused on reducing arrears and annual write-off amounts. While it is not our objective to terminate customers for nonpayment, terminations are necessary to support the objective of reducing the arrears and write-offs for all customers including verified low-income customers <250%, who represented ~22% of terminations in 2023. In regard to payment arrangements, PECO provided approximately 78,000 payment agreements in 2023.
- As I have already explained, we are conducting hundreds of outreach events to increase enrollment every year, and we are succeeding at ensuring that our low-income customers have sufficient assistance as well as access to a range of programs that can help them save energy.
- We process applications in a timely manner and provide a range of enhanced communications to assist customers with recertification as well as obtaining "retro" reinstatement credits for up to 12 months in which they may not have been on our CAP program due to a failure to recertify.

- The Company is utilizing technology to assist customers in connecting with assistance programs. In fact, as stated previously in my testimony, customers can submit CAP enrollment information online via PECO.com, noting that information explaining the program is provided in English, Spanish and Simplified Chinese. In addition, PECO's Assistance Finder provides customers with information on where they can go to apply for various programs including CAP, which makes the available online CAP application easier to access and therefore improve the enrollment experience for the customer. The Company also includes on our website the link to the DHS's Compass website where customers can apply for LIHEAP.

Finally, PECO collects information about the level of customer satisfaction of LMI customers. A third-party vendor surveys residential customers (by phone and digitally) after customer interactions with PECO. In addition to collecting information about customer satisfaction, those surveys ask customers to provide income information. Based on the survey responses, customer satisfaction improvement plans are developed to address themes of opportunity identified.

30. Q. Mr. Colton contends that PECO should amend its tariff Rule 17.4, Payment Processing to permit dual customers to designate that all or part of their combined PECO bill payment be applied to electric service –including past due balances and current charges –before being applied to natural gas service, or vice versa. Does PECO support the implementation of these recommendations?

A. No. PECO provides customers who receive electric and gas service with a total bill for their utility service, not one for gas and one for electric. There is no basis for permitting customers to "prefer" one service over another, and a customer in arrears is at risk for termination of both services.

31. Q. Ms. Marx makes several recommendations related to language access, including that PECO should: (1) track the primary language of its customers as part of its customer information system; (2) send residential bills (or key portions thereof) and residential termination notices in English and Spanish to all households; and (3) include a tagline about interpretation service in five languages on residential customer bills and termination notices. Does PECO agree with these recommendations?

A. No, PECO believes that its existing processes to address language access issues are appropriate and meet or exceed Commission requirements. Implementing Ms. Marx's proposals, including the proposed software upgrade for tracking a "primary" language of customers, would create new costs that PECO does not believe are warranted at this time.

With respect to written documents, PECO's current collection notices already include a sentence in Spanish alerting customers that the notice is important and that they should contact the Company for help if needed. Similarly, PECO's bills include a sentence in Spanish explaining how a customer can contact PECO if they have questions or concerns. When an LEP customer contacts PECO, they have access to translation service in over 100 available languages. PECO provides its CAP and LIHEAP applications in English and Spanish (in PDF format on

PECO's website and in hard copy at outreach events). PECO also provides our low-income program brochure in English and Spanish.

Furthermore, for low-income outreach events in Spanish-speaking areas / zip codes, PECO provides representatives fluent in spoken and written Spanish to conduct those events. For non-Spanish speaking LEP outreach events, PECO provides interpreters upon request. Those interpreters are typically members of LEP organizations with whom PECO partners. PECO provides documents such as assistance program brochures, the CAP application, the LEP language line card, and website translation assistance to community-based organizations and our customers in various languages.

32. Q. Please summarize Ms. Marx's recommendations regarding the determination of residential heating type.

Ms. Marx recommends additional customer touchpoints to determine if a customer is properly on Rate R or Rate RH, such as when a new customer account is opened, during LIURP audits, when a Rate R customer is approaching their CAP credit maximum, and when a Rate R customer has high winter usage. She further recommends revisions to tariff language to allow customers to enroll in Rate RH if they rely on electric heating equipment as a primary or supplementary heating source.

33. Q. Does PECO support the implementation of these recommendations?

A. No. Customers indicate their heat type when submitting a service and meter application, either at the time of a new connection or when they are applying upon an upgrade to existing service, which could be when they are upgrading from a

different fuel type to electric heat. If a customer or advocate contacts PECO to inform us that the customer has installed primary electric heating equipment consistent with Rate RH requirements, the Company will switch the customer to Rate RH upon verification based on their documentation of the equipment installed. High usage in the wintertime does not necessarily indicate electric heating and therefore does not warrant additional outreach requirements.

In addition, for high bill disputes, we have a care center process in place where we take information from the customer regarding a potential rate change, and if the customer appears to qualify, they submit information via email to PECO for review. Finally, PECO does not agree with a revision to the tariff language to allow customers to enroll in Rate RH if they rely on electric heating equipment as a supplementary heating source. I note that Rate RH is not designed to facilitate customer use of space heating in light of the cost and safety hazards of such equipment.

34. Q. Please summarize Mr. Colton's recommendations concerning processes related to residential security deposits and disconnections.

A. Citing the potential for discriminatory effects, Mr. Colton argues that the Commission should mandate additional review of certain PECO processes. First, he recommends that PECO's risk analysis methodology underlying its disconnection of service and cash security deposits should be subject to a public review by the Bureau of Consumer Services and stakeholders. Next, he argues that PECO should conduct a root cause analysis to determine and address the cause of an alleged "disproportionate" level of disconnections in certain zip codes

with relatively greater numbers of Black households. Finally, Mr. Colton recommends that PECO's Tariff be modified to state that its credit scoring methodology "does not directly, or have the effect of, discriminating based on a protected class as set forth in the federal Equal Credit Opportunity Act."

35. Q. Do you support Mr. Colton's proposals?

A. No. PECO's termination procedures, credit scoring, and other processes are applied equally to all customers and PECO does not target specific zip codes or classes of individuals. PECO's risk assessment procedures that are used to determine whether and/or when to schedule a disconnection of service to a residential customer for nonpayment are based on PECO's goal to improve its collection activities, decrease its annual write-off amounts, and reduce the overall cost of field collections activities. Factors used in the risk assessment include account balance, monthly bill amount, probability of cut success, percentage of balance paid if cut, percentage of balance paid if not cut, probability of account finaling if cut, and probability of account finaling if not cut. PECO does not know, nor does it track, customers by demographics such as race or ethnicity for purposes of disconnection.

I note that PECO partners with assistance organizations to identify and implement initiatives to remove barriers for underserved communities to access federal, state and local energy assistance funding. PECO contracts with 30 community-based organizations strategically located throughout PECO's entire service territory. These agencies are trusted by the communities they serve and PECO's affiliation with these organizations only serves to expand our outreach. Additionally, PECO

provides training to agency workers to ensure each agency is aware of PECO's comprehensive suite of assistance programs to maximize assistance options for LMI customers.

V. LARGE CUSTOMER ACCOUNT MANAGEMENT AND BILLING ISSUES

36. Q. City/PEA Witness McGraw alleges that PECO has trouble executing routine requests such as turning on electricity for new meters and responding to billing questions despite regular follow-ups." Do you agree?

A. No. PECO has assigned an Account Manager ("AM") that is dedicated to working directly with the City on all matters. The PECO AM is the primary point of contact for more than twenty (20) City departments including, for example, Streets, Parks and Recreation, Water, and License and Inspection. The AM directly supports or coordinates within PECO most of the inquiries from these departments and ensures seamless communication and excellent customer service. The PECO AM is available to receive the City's questions and concerns on a 24/7 basis, meaning that the City can connect with the PECO AM at any time during the day or the night. In addition, the PECO AM has an assigned "back-up buddy" to assist the City when the PECO AM is not otherwise available. In addition, each large customer, including the City, is provided with an toll-free number that rings to the on-duty shift manager in case of more urgent after-hours needs.

The City's designated PECO AM has the primary responsibilities delineated below.

1. ***Consolidation, review and distribution of monthly invoices for all of these departments within the City***. This includes ensuring billing accuracy and

promptly addressing any discrepancies.

2. ***Receive and review all new service requests from City departments***. This involves coordination with various internal teams to assess the feasibility, plan the service implementation, and ensure timely delivery.

3. ***Collaborate with the City's internal teams, such as regional engineering and billing, to resolve any customer concerns***. This collaboration is crucial for addressing technical issues, ensuring accurate billing, and maintaining high customer satisfaction.

4. ***Serve as the emergency contact for addressing outage related concerns after hours and during weekends***. The PECO AM works directly with the outage control center to ensure swift resolution of any power outages or disruptions to minimize the impact on City operations.

5. ***Attend monthly check-in meetings with the Office of Sustainability.*** During these meetings, the PECO AM addresses any open requests or issues related to sustainability projects and energy usage, ensuring alignment with the City's sustainability goals. The PECO AM also attends scheduled meetings with the other departments as requested by the City.

6. ***Provide support to the City's sustainability efforts by gathering and providing relevant information***. This includes data on energy consumption, efficiency measures, and other sustainability initiatives. The PECO AM also ensures that the City has the necessary information to make informed decisions to meet its sustainability targets.

Regarding concerns related to executing routine requests expressed in Mr.

McGraw's testimony, I note that PECO has defined procedures and practices in place that require information to be obtained prior to energizing a new service, stopping a service, and making sales tax and billing changes. The City's account is complex and has numerous touchpoints and resolution of specific issues often requires feedback from and communication with the City as well as their various contractors who submit these requests. However, while PECO's resolution of specific requests can take time to review, coordinate and implement given the intricacies of the City's account, PECO makes every effort to respond to all requests in a timely fashion.

With specific respect to the City's billing questions, historically, the PECO AM would research the question at hand and take the appropriate actions to address the issue. These actions can range from providing a billing explanation to submitting requests to the billing department to update and/or revise the bill. In the instance of the need to issue a new bill reflecting required changes, the new bill would be generated during the next billing cycle, where it is once again reviewed for accuracy by the PECO AM. It should be noted that the City, in addition to its numerous departments, has multiple contractors that also coordinate with different departments within PECO (in other words, not just the AM) specifically to make requests for starting and stopping service. Not surprisingly, these additional interactions can further complicate the City's account. Despite this, the PECO AM remains in constant communication with the City and provides timely updates on existing known issues or captures newly identified issues, at each standing monthly check in meeting, as well as during the

many ad-hoc follow up calls and meetings.

In response to Mr. McGraw's comments regarding availability of account numbers after the billing system transition, PECO notes that implementation of the new billing system, customers were directed to utilize an online look up tool or wait to see their new account number on the first bill generated from the new system. After implementation of the new billing system, PECO created a customized solution for the City to access new account information by providing it with an excel spreadsheet containing a comprehensive list of all the City's old and new account numbers as well as other relevant account information. If PECO had not provided this information, the City would have had to manually look up each account number one at a time using the on-line tool or wait until it received the first bill generated from the new billing system to retrieve new account information.

In addition, during conversations with the City over the past few months, the PECO AM has informed the City that PECO is continuing to address billing exceptions that may impact the City, such as the bill presentment issue mentioned by Mr. McGraw, and will continue with its process of providing regular updates when available as we work to resolve any outstanding exceptions they may have.

37. Q. Mr. McGraw testifies that the City has faced difficulty working with PECO on its LED streetlighting project as it relates to PECO's response to questions about PECO-owned equipment on poles. Can you please provide an update?

A. I do not believe that this is an outstanding issue.

The City informed PECO that it faced challenges getting information related to PECO equipment attached to the City's streetlight poles. At the initial meeting, which took place on October 12, 2023, the City stated that it encountered ten (10) devices that were attached to its streetlight poles while it was completing the first thirty thousand (30,000) installations of LED lights and asked PECO for direction on how to remove them. At the time, PECO assumed that the devices had most likely been abandoned in place in 2017 and would be removed by PECO when the opportunity presented itself during routine maintenance on PECO equipment. PECO reviewed the matter and confirmed to the City that they would work with the City to determine a process to remove the devices.

PECO had to then determine who was responsible for the cost of removal and what field personnel would remove the devices (e.g., PECO or the City's contractor). The City's contractor cost for removal was four times PECO's cost of removal. After internal review and coordination with the City, PECO agreed to remove the devices at PECO's cost. However, when PECO sent personnel out to remove the ten (10) devices, only seven (7) devices were discovered and of those seven (7), only five (5) of them were PECO devices. PECO removed the five devices and notified the City of the status. PECO also agreed to utilize the "City Works" portal (the City's preferred method of communication) to obtain appropriate information if the City should discover other PECO devices in the future. In addition, moving forward, the City and PECO agreed that PECO crews will remove any devices from the city-owned streetlight poles at PECO's cost.

38. Q. Mr. McGraw also takes issue with and provides examples of administrative

issues related to PECO's implementation of a new billing system in February 2024. Can you provide an update regarding resolution of the City's billing issues?

A. Prior to implementation of the new billing system, PECO met regularly with its large customers, including the City, to discuss the implementation timeline and related administrative matters and since implementation, PECO has been in frequent contact with the City.

With respect to the specific issues Mr. McGraw references, PECO has resolved four of the five issues and is currently working to resolve the remaining outstanding issue related to bill presentment. We will continue to provide updates to the City as soon as they are available.

39. Q. How do you respond to Mr. McGraw's recommendation to "establish service-level agreements ("SLAs") for requests handled by account managers, both for routine billing questions as well as requesting surrounding sustainability project" to ensure customer needs "are being met in a timely manner"?

A. PECO believes that large customer needs, including those of the City's, are being met on a timely and consistent basis. Before responding directly to Mr. McGraw's recommendation to establish an SLA between PECO and the City, I want to highlight the direct testimony submitted by Lisa V. Perry on behalf of Walmart, Inc., another large PECO customer. Specifically, at pages 23-25 of her direct testimony, Ms. Perry commends PECO for establishing a "key account management team dedicated to engaging with and addressing the unique needs of

its larger customers" and provides detailed testimony about the importance of the relationship between the account representative and the large customer so to "inform the Commission of the valuable service provided by the Company's key account management team."

In responding to Mr. McGraw, I note again that, as with Walmart, due to the size and complexity of its account, the City receives a highly customized, premier level of service with a designated 24/7 PECO AM that is responsible for being the point of contact for the City's customer service needs, including manual consolidation, review and distribution of monthly invoices for the more than twenty (20) departments within the City.

Also, as discussed above, the PECO AM ensures the City's needs with respect to sustainability efforts are being met by gathering and providing relevant information with the support of other internal stakeholders and attending monthly check-in meetings with the City's Office of Sustainability. This information includes but is not limited to providing data on energy consumption and efficiency measures which allows the City to make informed decisions and meet its sustainability targets.

For these reasons, PECO does not believe that an SLA is necessary given the personalized customer service that the City enjoys today by virtue of having a single point of contact to coordinate and facilitate resolution of its customer service requests.

40. Q. The testimony of SEPTA witness Crist raises similar concerns with respect to account management and billing issues for large customers and testifies that

"[t]hese have all been relayed to PECO but there has been no follow up on confirmations of the timing for resolution." How do you respond to this statement?

A. As with the City, PECO met with large customers, including SEPTA, before implementation of the new billing system to discuss changes and timelines, and we have been in frequent contact throughout the process. In fact, in his direct testimony, Mr. Crist provided a copy of the notification in October 2023 PECO provided regarding the transition to the new billing system in 2024.

In addition, after implementation, the PECO AM for SEPTA has had regular meetings and multiple phone calls with the SEPTA Management Analyst regarding billing exceptions, including bill presentation and summary bill. Resolution of exceptions is a top priority for PECO and we are working diligently to resolve any outstanding issues, including invoice delivery and confirmation of account additions and deletions from SEPTA's billing. PECO continues its commitment to keeping SEPTA fully informed throughout the resolution process.

41. Q. Mr. Crist also raises concerns regarding the Company's customer portal and the removal of information regarding Installed Capacity ("ICAP") and Network Integration Transmission Service ("NITS"), "which are important data for customers that receive electric commodities from third party suppliers" because the data allows them "to verify if they are being invoiced correctly and with the correct billing variables." Mr. Crist goes on to recommend that PECO resume providing access to ICAP and NITS data on the portal, including interval data. What is your response to this

recommendation?

A. First, with respect to Mr. Crist's concerns related to the removal of account-level ICAP and NITS transmission tags on the customer portal, I note that the decision to remove customer access to that information was made by PECO security in response to an increase in cybersecurity attacks among large companies and is unrelated to the implementation of PECO's new billing system. PECO felt it was prudent to take proactive measures to protect our customers and their employee account information from these growing threats.

Second, billing variables such as ICAP and NITS transmission tags are available to customers upon request. In fact, SEPTA's PECO AM has provided SEPTA's consultant with ICAP and NITS tag information. Currently, PECO's information technology and business departments are working to identify a solution to resume direct accessibility by customers and will keep SEPTA updated accordingly. Finally, as for Mr. Crist's recommendation regarding interval data, this past May, PECO started work to integrate our third-party portal, which provides interval data for large commercial and industrial customers, with the new billing system. We are now in the second phase of this project and anticipate that the new portal will launch later this year and provide improved access of information for our customers.

VI. CUSTOMER SERVICE AND SATISFACTION

42. Q. In his testimony, OCA witness DeMarco notes customer service improvements the Company has made with its website and Mobile App and increased enrollment in "My Accounts" for both PECO Gas and PECO

Electric but expresses concern that the Company does not identify the cost savings associated with these improvements.

A. The "My Accounts" enrollments for both the website and mobile app have increased for residential customers. However, since this technology offering is relatively new to customers, it is premature to quantify cost savings associated with this improvement. It is important to note that this technology is designed to facilitate an improved customer experience and ease for customer of access to customer account information, and an overall cost savings may be difficult to quantify.

43. Q. Do you agree with Mr. DeMarco's recommendation to implement a "two-step identification" process to protect customer account information?

A. I disagree with Mr. DeMarco's recommendation to implement Two-Step Identification because the process is already a part of our customer security protocol. Voluntary Two-Step Identification went live as part of our offering in the first quarter of 2022. Mandatory Two-Step Identification for new residential customers is scheduled to go live by the end of 2024 and for all residential customers in 2025.

44. Q. Mr. DeMarco claims that the Company has made inconsistent statements about whether the improvements and costs savings associated with the website and the Mobile App form the basis for its request for a management performance adder and requests clarification in rebuttal. Can you please respond?

A. I disagree that the statements are inconsistent. For example, as Ms. LeVine testified in her direct at page 26, lines 5-12, the Company added "other features and capabilities" to the PECO website. In response to OCA-16-3, Ms. Levine answered "no" as to whether her discussion of the added "features and capabilities" supported the management performance adder. While the new "features and capabilities" alone do not support the management performance adder, the success in terms of customer efficiency and support that has been achieved through the Company's proactive implementation of the additional "features and capabilities" that were identified in Ms. LeVine's direct testimony contributes to the Company's recommended addition of fifteen (15) basis points to the allowed return on equity for management performance.

45. Q. Please summarize Mr. DeMarco's concern about the Company's plan to improve customer satisfaction.

A. Mr. DeMarco states that the Company fails to define its objectives or provide support for how it plans to reach its objectives. He further alleges that the Company has not performed a cost-benefit analysis or identified any goal metrics to assess results. He states that a management performance adder is appropriate only once those improvements are in place.

46. Q. How do you respond to his concern that the Company did not define its objectives or providing support for how it plans to reach its objectives?

A. PECO's plan to improve customer service begins with routine customer satisfaction surveys administered by a third-party vendor throughout the year. PECO's third-party vendor will randomly select residential customers and contact

them either by phone or email to solicit feedback on various customer service topics. For commercial customers, the vendor reaches out directly by phone to discuss PECO's level of customer service. After PECO receives and studies the survey responses, the Company takes action to implement solutions to address any concerning feedback provided by the customers. As an example of actions taken, in 2023, PECO enhanced the promotion of digital adoption, which increased the web activity for billing and payment options. The Company also sent out 3.1 million emails to educate customers about price-to-compare and created an animated video about third-party suppliers for additional education. Moreover, in response to survey feedback from small and medium business customers, PECO assigned account managers (just like the ones assigned to the large customers). As a result, PECO has created more touch points with this customer class and our outreach has increased significantly.

In 2024, PECO continues to focus on improving customer satisfaction by strategically communicating with customers to promote self-service tools including My Account and e-bill. PECO has developed a new self-service video to explain how to use the new tools, and is currently developing a new *'Understanding Your Bill'* customer video. The self-service offerings allow customers to do business with the Company when it is convenient for them, which is often after regular business hours and on the weekend. I can report that we are seeing positive results. For example, self-service adoption grew approximately 22% between 2022 and 2023 (from 5.3 million users to 6.5 million users) with utilization of the Company's self-service offerings increasing nearly 21% between

2022 and 2023.

Finally, as I discuss in more detail below, PECO is focusing on the CSR component of customer satisfaction as evidenced by the "Universal Agent" training.

47. Q. Do you agree with Mr. DeMarco assessment of the Company's plan to improve customer satisfaction?

A. No. I disagree with Mr. DeMarco's assessment of the Company's plan to improve customer satisfaction primarily because the Company has identified strategies to improve customer satisfaction year-over-year. Such strategies include using targeted communications to promote self-service tools and services available to customers including MyAccount and e-bill enrollments. As noted above, the Company is incorporating new self-service videos in PECO's external outreach and is currently developing a new *'Understanding Your Bill'* customer video. Lastly, the Assistance Finder tool uses technology that helps customers find programs designed to support their specific needs all in one place.

48. Q. Do you agree with Mr. DeMarco that the Company has not supported its claim that customer benefits will come from investment in customer operation?

A. No. The investments implemented to date are designed to improve the availability of customer products and the reliability of the underlying platforms. As I noted above, these projects consist of enhancing digital self-service options and offering personalized solutions that meet customers' needs. One investment to "help promote and improve affordability" is "My Account," which has enabled

customers to navigate more efficiently and utilize online options to manage their individual needs. The use of Assistance Finder tool provides customers with personalized program recommendations to allow them to manage their bills and energy usage and, as mentioned previously in my testimony, helps them find programs designed to support their specific needs all in one place.

VII. CALL CENTER PERFORMANCE

49. Q. Mr. DeMarco recognizes 2023 improvement in PECO's call abandonment rate and average calls answered within 30 seconds but notes that PECO has not reached its goal for the 2022-2025 period. How do you respond?

A. PECO sets aggressive internal targets for the call abandonment rate and the percent of calls answered within thirty (30) seconds to meet customer needs. PECO achieved significant improvements in both call abandonment rate and the percent of calls answered within thirty (30) seconds from 2022 to 2023. While these metrics are important and will continue to be a focus of the Customer Care team, we believe that First Contact Resolution ("FCR") is a better measure of the ease of doing business with PECO. The abandonment rate and the percent of calls answered within thirty (30) seconds are an indication of how quickly calls are answered while FCR is an indication that the customer's issue was resolved on the first attempt. Customer satisfaction research has indicated that resolution of the customer's issue on the first attempt is a higher priority to the customer than short wait times. Our Customer Care team is focused on making improvements in this area.

50. Q. Mr. DeMarco acknowledges the Company's improvement to call center performance through implementation of a FCR approach and a "Universal Agent" strategy. Do you agree with his recommendations to conduct further analysis on how to improve the FCR process and investigate any issues regarding call handling that have not been resolved since the July 2022 Audit Report?

A. No. In fact, prior to the July 2022 Audit Report, upon its own initiative the Company transitioned to FCR and made it a top priority metric for Customer Care. Customer Care has made several changes to enhance FCR since that time, including increasing call evaluations, implementing a new process flow tool for agents, realigning resources within the organization to increase agent coaching support, and investigating FCR by call type to identify opportunities for process improvements. In a sense, the Company has already implemented Mr. DeMarco's recommendation as Customer Care continues to focus on ways to improve FCR.

51. Q. Citing UCARE statistics, Mr. DeMarco notes an increase in the number of customer complaints and verified infractions. He recommends the PECO create a plan with metrics to reduce the level of information complaints and verified infractions. Do you agree?

No. First, let me say that PECO's operations team continually strives to minimize the number of customer complaints and verified infractions, and as I noted above, conducts third-party surveys throughout the year to identify areas of improvement and provide solutions. Second, I believe Mr. DeMarco is incorrect about an increase in the number of residential complaints and verified infractions. If 2021

is excluded from the data – consistent with OCA Witness Colton's argument that 2021 was an atypical year (Statement 4, pages 104-106)) – the results show a decrease in residential complaints and a "remains steady" trend in verified infractions.

Third, I direct Mr. DeMarco to BCS's "Quarterly Update to UCARE Report for January—December 2023" which demonstrates that in 2023 PECO had the lowest residential complaints rate of all Pennsylvania electric utilities (the rate is calculated by the number of complaints per 1000 customers). Specifically, PECO's Volume Rate for residential complaints was 1.0. Likewise, with respect to verified infractions, PECO performed at the top of all Pennsylvania utilities with an Infraction Rate of 0.10.[13] In this regard, the data shows that PECO is leading the way.

For these reasons, I disagree with Mr. DeMarco's recommendation that PECO should conduct a root cause analysis and create a plan with actional metrics providing how PECO will reduce informal complaints and verified infractions.

52. Q. In response to questions about bill payment options and fees, Mr. DeMarco notes discovery regarding fee revenues from transactions (pay as guest and by phone) received from customers had not been received from the Company. Can you provide an update?

[13] Quarterly Update to UCARE Report for January—December 2023, https://www.puc.pa.gov/media/2754/ucare_2023_q4.pdf

A. PECO provided the responses to the interrogatories referenced by Mr. DeMarco in this proceeding on June 14, 2024, and confirmed that the Company does not receive revenues from customer payment fees.

53. Q. Mr. DeMarco expresses concern about the potential for discrimination by charging customers a fee to pay their bill when they are not doing so via My Account or when they pay by phone and recommends that PECO eliminate these fees as a direct cost to consumers. Do you agree?

A. No, I note that PECO offers multiple no fee payment options, including mailing payments directly through the United States Postal Service, submitting an electronic payment (e-check) via MyAccount or the customers' bank or third-party institution, as well as for those customers that have a MyAccount but wish to pay by phone, with agent assisted payments using e-check.

Additionally, while a payment fee initially is charged to customers who make payments at authorized bill payment locations (e.g., large retail stores and drug stores) via check, cash, or credit card, payment fees collected are reimbursed to the customer on their next bill. PECO began the process of reimbursing the fee for walk-in payments in recognition of supporting our most vulnerable communities. In 2023, for example, more than two hundred and fifty thousand (250,000) payments were made at authorized bill payment locations. Importantly, more than half – sixty four percent (64%) or ninety-four (94) out of one hundred forty-six (146) of the available authorized bill locations – are in the City of Philadelphia, where a majority of PECO's low-income customers are geographically located and most likely to utilize this payment option. Moreover,

the fees associated with payments made at authorized bill locations are absorbed by the Company at a cost of approximately five hundred thousand dollars ($500,000) annually.

The fees assessed for payments made outside of PECO's no-fee payment options are primarily associated with the processing of debit and credit card payments and are collected by the third-party processing vendor. As I am sure Mr. DeMarco is aware, credit card companies can charge significant fees for payments or purchases. The fees assessed to customers utilizing these methods are intended to offset the credit card fees assessed by the credit card industry. If PECO were to include these third-party processing vendor fees in its revenue requirement, this could potentially increase the revenue requirement by a minimum of five million dollars ($5,000,000) annually for residential payments, which is an amount that would be collected from all customers, including those currently using the no-fee payment option**.**

54. Q. Regarding Personal Identification Information ("PII"), Mr. DeMarco is waiting for discovery responses from the Company. Can you provide an update?

A. The discovery responses for OCA-21-12 and OCA-21-13 were served to the parties on June 16, 2024.

55. Q. What is your response to Mr. DeMarco's recommendation that PECO reduce the use and retention of PII and develop workflow and cybersecurity measures to reduce the threat of disclosure or theft of PII?

A. I would refer Mr. DeMarco to the discovery served to the parties in response to OCA OCA-21-12 and OCA-21-13. PECO follows industry best practices around cybersecurity to safeguard and protect customer's PII. This includes, but is not limited to, multiple levels of access restrictions and encryption. However, due to the nature of PECO's business as a provider of retail electric and natural gas service, the retention of customer PII is vital to reduce the likelihood of fraudulent accounts being created and to provide needed creditworthiness information upon the creation of new accounts.

VIII. CONCLUSION

56. Q. Does this complete your rebuttal testimony at this time?

A. Yes, it does.

PECO ENERGY COMPANY
STATEMENT NO. 10-R (Corrected Version)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

REBUTTAL TESTIMONY

WITNESS: JAQUELINE F. GOLDEN

SUBJECT: LOW-INCOME CUSTOMER ISSUES; RECOVERY OF CUSTOMER ASSISTANCE PROGRAM COSTS; RESIDENTIAL CUSTOMER ISSUES; CUSTOMER SERVICE AND BILLING ISSUES

DATED: JULY 16, 2024

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REBUTTAL TESTIMONY
OF
JAQUELINE F. GOLDEN

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Jacqueline F. Golden. I am employed by PECO Energy Company ("PECO" or the "Company") as the Director of Customer Financial Operations. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct testimony marked as PECO Statement No. 10. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will address the following topics raised by other parties in direct testimony.

Low-Income Customer Issues: I will respond to the direct testimony of Elizabeth R. Marx on behalf of the Tenant Union Representative Network ("TURN") and the Coalition for Affordability Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") (collectively "TURN/CAUSE-PA"), the direct testimony of Mr. Roger Colton on behalf of the Office of Consumer Advocate ("OCA"), and the direct testimony of Elizabeth H. Lankenau on behalf of the City of Philadelphia and the Philadelphia Energy Authority (collectively, "City/PEA") concerning bill affordability, the definition of "confirmed low-

income customer", customer noticing regarding PECO's Customer Assistance Program ("CAP"), the use of speech analytics software, security deposit policies, and proposed changes to several of the Company's Universal Service programs.

Universal Service Fund Charge ("USFC") Offset Factors Costs: I will respond to Mr. Colton's testimony concerning the bad debt offset factor in the USFC formula.

Residential Customer Issues: I will respond to Mr. Colton's and Ms. Marx's proposals concerning language access, methodologies used for security deposits and termination scheduling, customer touchpoints regarding Rate R / Rate RH designation, and the application of customer payments to dual customer bills. I will also address Mr. Colton's contention that PECO is not providing exemplary service in the areas of Universal Service, credit and collections.

Customer Service Issues: With respect to large customer account management and billing issues, I will respond to the direct testimony of James L. Crist on behalf of the Southeastern Pennsylvania Transportation Authority ("SEPTA"), as well as the direct testimony of Dominic G. McGraw on behalf of the City/PEA. I will also address direct testimony provided by OCA witness Nicolas A. DeMarco regarding customer service and satisfaction, call center performance and billing matters. I also note the supportive direct testimony provided by Lisa V. Perry on behalf of Walmart, Inc.

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

A. Yes, I have prepared PECO Exhibit JFG-1 which I describe later in my testimony.

II. LOW-INCOME CUSTOMER ISSUES

5. Q. Ms. Marx, Mr. Colton and Ms. Lankenau each emphasize concerns about affordability for low-income customers in response to the Company's proposed base rate increase. Please describe the Company's existing efforts and proposal in this proceeding to connect customers in need with programs that can reduce their bill.

A. PECO has a robust Community Education and Outreach Plan ("CEOP") to facilitate customer awareness of and connection to assistance programs, along with enrollment in, the Company's Universal Services offerings. The CEOP is filed with the Commission, shared with PECO's Universal Services Advisory Committee ("USAC"), and updated on an annual basis. PECO conducts hundreds of outreach events in coordination with community-based organizations throughout the Company's service territory every year and utilizes both U.S. Census (zip code data for low-income and limited English proficiency "LEP" areas) and PECO customer data (zip codes with the highest termination rates) to determine event locations. When an event is focused on an LEP community, the Company provides interpretation services. PECO also partners with dozens of social service agencies by providing them with Universal Services materials and educating their staff (as well as customers) about important concepts such as income eligibility (i.e., how to read and interpret the Federal Poverty Level ("FPL") chart). PECO also sends CAP-specific mailings and conducts outbound calls to confirmed low-income customers and non-CAP recipients of Low-Income Home Energy Assistance Program ("LIHEAP") grants to encourage them to apply to CAP and provide instructions on how to apply. Additionally, the Company

provides all new residential customers with a welcome packet which includes information on assistance services, such as CAP, the Matching Energy Assistance Fund ("MEAF"), the Low-Income Usage Reduction Program ("LIURP"), the Customer Assistance Referral and Evaluation Service ("CARES") and LIHEAP.

The Company has further integrated virtual outreach and enrollment activities and extensive programmatic information on its website (peco.com/help) to expand the ways in which customers can learn about assistance programs. This information is available on PECO's website in Spanish and Simplified Chinese. PECO has also implemented the Assistance Finder tool on PECO's website, which provides customers with access to information on financial assistance, bill management, and saving money and energy (e.g., PECO's Universal Services programs). In fact, from May 2023 through April 2024, almost 40,000 customers completed the survey in the tool and received personalized program recommendations along with nearly 5,000 customers submitting CAP applications. In addition, PECO monitors its education and outreach performance by tracking a variety of metrics, including some specific to activities for customers at or below 50% of the FPL as noted in the Company's 2024 CEOP filing.

The Company will continue these efforts and provide further enhanced outreach services with the incremental request of $300,000 proposed in my direct testimony. The additional funding will build upon existing efforts and enable PECO to: (1) connect more eligible customers with LIHEAP funds; (2) ramp up virtual enrollment activities for Universal Service programs; and (3)

accommodate an increase in customer referrals that is tied to the Company's outreach efforts.

6. Q. Ms. Marx and Mr. Colton each contend that PECO's definition of a "confirmed low-income customer" is not consistent with PUC regulations and recommend that PECO's tariff and policies reflect a definition that includes, among other things, customers who self-certify income without additional documentation. Please respond.

A. I disagree that PECO's definition of a "confirmed low-income customer" is inconsistent with PUC regulations. PECO defines "confirmed low-income" as customers who, in the last two years, have provided verified financial information (i.e., proof of income documentation) at or below 150% of FPL, and/or enrolled in CAP, and/or received a LIHEAP grant. This description is consistent with electric and gas regulatory definitions of "confirmed low-income residential account" which both refer to a utility obtaining "information that would reasonably place the customer in a low-income designation."[1] Utilities are not required to accept self-certification without additional documentation.[2]

7. Q. Mr. Colton recommends that PECO utilize speech analytics software to assist with the quality monitoring of calls involving, or potentially involving, Universal Service programs and other low-income customer issues. He further recommends that PECO involve its USAC in terminology selection

[1] 52 Pa. Code 54.72 (electric); 52 Pa. Code 62.2 (gas).

[2] The regulatory definition applicable to Natural Gas Distribution Companies ("NGDCs") at 52 Pa. Code §62.2 identifies self-certification as a type of information a NGDC *may* accept.

and report on monitoring results to the USAC. Please respond.

A. PECO's call center employs a natural language processing analytics solution to help the Company better understand reasons for calls and identify opportunities to improve processes and customer service representative performance. The Company currently uses this analytics solution to identify calls on current news publications, price impact on customer sentiment, system changes, and whether a customer may be having technical issues. PECO is open to sharing common search terms with the USAC.

8. Q. Please summarize Ms. Marx's recommendations concerning the collection and refund of security deposits from low-income customers.

A. Ms. Marx recommends that PECO: (1) educate customers about the low-income security deposit exemption and income screening customers prior to assessing a security deposit; (2) within 30 days of final order in this proceeding, review all prior security deposit collection from low-income customers, issue refunds and continue the monthly review moving forward; and (3) issue refunds as appropriate directly to customer, with account credits used only if the customer consents.

9. Q. Do you support the implementation of those proposals?

A. No. By way of background, I would like to explain the Company's processes with respect to low-income customers and security deposits.

When a new residential customer requests a connection for service, a deposit will be assessed based on the information provided by a third party vendor, whether the customer has limited or no credit history, or if the customer has a prior written off or "finaled" delinquent PECO account. If the customer says that they cannot

pay the assessed deposit, PECO informs the customer that PECO will send a letter with contact information that the customer can use to call and speak to a Company representative regarding the customer's income information and request to waive the deposit after verifying their low-income eligibility for such a waiver. Customers who are verified low-to-moderate income ("LMI") $\leq$ 250% of FPL are excluded from being assessed a deposit.

PECO also reviews existing accounts to determine if a deposit may be required depending on where a customer may be in the collections process. Typically, a deposit is required if the customer meets the following criteria:

- There is not already a deposit assessed on the account;
- Late payment charges have been applied three times in the prior 12 months; and
- The account has received a deposit warning in the prior four months

If the first two conditions are met, but the third is not, PECO will send a deposit warning, rather than assess a deposit. In this instance, customers who are verified LMI $\leq$ 250% of FPL are also excluded from being assessed a deposit.

PECO also regularly reviews residential accounts to ensure that deposits have been properly assessed. If a customer paid a deposit and becomes a verified LMI customer subsequent to paying the deposit, PECO will apply the deposit to the customer's account to reduce the amounts they would otherwise owe. If a customer who does not need to maintain a deposit contacts PECO to request a cash refund of a security deposit credit, PECO will issue a check in the amount of any excess credit on the customer's account.

In sum, customers who are determined to require a deposit are excused from deposit obligations upon income verification, with credits or refunds available where appropriate. I do not believe there is any reason to change PECO's existing security deposit procedures.

A. Customer Assistance Program

10. Q. Please summarize Ms. Marx's recommendations concerning CAP enrollment processes.

A. Ms. Marx makes several enrollment-related recommendations, including: (1) participation by PECO in the Department of Human Services ("DHS") data sharing program; (2) routine Universal Services screening for new, moving and non-emergency calls, including a warm transfer process if necessary; and (3) automatically enrolling or recertifying customers following receipt of a LIHEAP grant, which could include an "opt-out" component.

11. Q. Do you agree with Ms. Marx's proposals?

A. The Company is actively considering participation in the DHS data sharing program and, if the Company elects to participate, it will file a letter by July 31, 2024 as directed by the Commission.[3] The Company disagrees, however, with the proposal concerning routine screening. If a customer calls to discuss a past due balance, identifies affordability concerns, or asks about Universal Services programs, the Company already asks about income status to screen for potential CAP eligibility, establish payment arrangement terms, and advise of other

[3] *2023 Review of All Jurisdictional Fixed Utilities' Universal Service Programs*, Docket No. M-2023-3038944 (Order entered June 13, 2024).

assistance programs and external grant programs available. PECO does not agree that it would be appropriate to ask all customers about their income during all other types of non-emergency customer service calls (e.g., moving to a new service address) given that the purpose of the customer's call was not related to affordability or assistance programs and the Company would be requesting information that the customer may not be comfortable providing.

Regarding enrollment processes, the Company disagrees with the proposals on automatic enrollment. PECO believes customers should maintain the ability to affirmatively choose whether or not to enroll in CAP or participate in any other low-income program. While auto-enrollment may offer benefits to a customer in the form of bill discounts, it may also restrict other types of customer activities. For example, if a PECO customer is enrolled in CAP they cannot shop for an electric supplier, utilize budget billing, or retain their one-time opportunity for Pre-Program Arrearages ("PPA") forgiveness if they do not currently have a significant past-due balance. Furthermore, customers should have the opportunity to understand the specific program benefits and requirements before being enrolled in CAP.

Additionally, while the Commission has encouraged utilities to consider implementation of auto-enrollment of LIHEAP recipients into CAP, PECO believes that in addition to customers maintaining their right to affirmatively choose whether or not to enroll in CAP, it is important to consider the increased costs to all residential customers, including CAP and non-CAP LMI, of auto-enrollment. In 2023, PECO received LIHEAP grants for approximately 10,000

non-CAP customers. Using the forecasted 2025 average annual CAP bill credit of approximately $1,200,[4] auto-enrolling these customers in CAP would increase bill credits by up to $12 million. Additional enrollments of future non-CAP LIHEAP recipients would further increase bill credit costs. And while Ms. Marx proposes an "opt-out" option (i.e., auto-enrollment occurs unless a customer affirmatively chooses to "opt out" of any auto-enrollment), such an approach can be expected to also result in higher cost associated with CAP back office administration, PIPP correspondence mailings, and Information Technology ("IT") implementation costs.

In addition, regarding recertification, PECO's Universal Service and Energy Conservation Plan ("USECP") already provides for an extended recertification cycle for LIHEAP recipients. Specifically, CAP customers who receive LIHEAP grants may recertify on a four-year cycle instead of the standard two-year cycle. Finally, as described in more detail in PECO's USECP, if a customer is removed from CAP and then re-enrolls within the following 12-month period, the customer is entitled to receive credits reflecting the CAP bill credits they would have received if they were enrolled during that period.

12. Q. Please summarize Mr. Colton's proposals concerning additional customer contacts during disconnection and reconnection related to CAP.

A. Mr. Colton recommends that PECO make personal contact with a confirmed low-income customer prior to disconnection to offer the opportunity to apply for CAP

[4] The Company is forecasting an average annual CAP bill credit of $1,216 in 2025 (2025 total CAP credit forecast of $159.2 million divided by the 2025 average CAP enrollment forecast of 130,875).

and the associated arrearage forgiveness. If the customer expresses a desire to apply, Mr. Colton proposes that PECO postpone the disconnection for a reasonable period of time to allow the CAP application process to be completed. When a confirmed low-income customer is being reconnected, Mr. Colton proposes that the customer be required to affirmatively acknowledge that they do not wish to participate in CAP (along with its arrearage forgiveness program) prior to being reconnected and required to pay either a portion of their outstanding arrears or any reconnection fee.

13. Q. Do you agree with his proposals?

A. No, PECO's existing termination noticing process already provides customers with appropriate information about the availability of assistance programs as well as how to contact the Company about other customer protections that may prevent termination. PECO's terminations of service are performed consistent with Commission regulations and include repeated notices for each customer. A customer at risk for termination of service first receives a 10-day notice, which includes specific information on contacting PECO, availability of assistance programs, and rights a customer may have to continue service. A customer who receives this notice and then contacts a PECO customer service representative ("CSR") will be granted a 10-day collections hold following any credit call with the CSR that does not result in taking the customer out of collections. Likewise, a 10-day collections hold will be granted by the Interactive Voice Response ("IVR") when a customer seeks to use the minimum payment option or to enter into a deferred payment agreement but is unsuccessful in doing so. This permits

the customer time to provide proof of income to enroll in CAP, make a payment, or request a payment arrangement if eligible.

If a customer still does not take action, PECO attempts to directly contact the customer 72 hours prior to termination through calls or direct contact by leaving a physical notice at the property, again with information that they may be eligible for available assistance and customer rights. When a customer calls PECO to make a payment to avoid termination or to reconnect, the CSR will explore options with the customer, which may include taking an income statement to confirm eligibility for longer payment arrangement terms and providing information about Universal Services program enrollment.

If a customer expresses the desire to apply for CAP, the customer is provided with instructions on how to access the online portal and/or pdf application. If the customer requests a paper copy, they are mailed a CAP application. CAP applications can be submitted via mail, email, fax or the online portal, and as previously stated the customer has ample time to apply once the 10-day hold is placed on their account.

If termination does occur, the customer is provided with yet another notice of the steps they can take to restore service. If the customer demonstrates that they are confirmed low-income and are a first time CAP customer, they may be eligible for restoration with the full balance to be set aside under PECO's PPA forgiveness program. In sum, during pre- and post- termination calls, if a CSR determines that a customer may be low-income based on the information the customer provides on the call, the CSR will provide information on Universal

Services programs including CAP and the discussions with the customer, including the customers decisions, are noted on their account.

14. Q. Please summarize Mr. Colton's proposals concerning "stand alone" noticing related to CAP.

A. Mr. Colton recommends that PECO provide stand-alone notices concerning CAP and associated arrearage forgiveness in the following situations: (1) when a customer is found to be without heating during cold weather survey; (2) when negotiating a deferred payment agreement with a confirmed low-income customer or a customer where information is generated during the payment arrangement process to place them in the Tier I income range (at or below 150% of FPL); (3) when a confirmed low-income customer has accrued an unpaid balance of $300 or more; and (4) when requesting a cash security deposit from a confirmed low-income customer.

15. Q. Do you agree with his proposals?

A. No, PECO's existing processes already provide customers with appropriate information about CAP and other Universal Services programs. First, customers identified through the winter survey process already receive a range of materials from the Company, including a CAP Application, Universal Services Program Information Sheet, and a LIHEAP Application during LIHEAP season. Second, when a Tier 1 confirmed low-income customer is negotiating a deferred payment arrangement, they are provided information about CAP and how to apply. Third, confirmed low-income customers routinely receive information about CAP,

regardless of their unpaid balance, and how they can enroll, including automatic mailings of CAP applications to non-CAP LIHEAP recipients.

Further, PECO conducts annual CAP outreach via direct dialed phone calls in May and U.S. mailing in October to confirmed and unconfirmed low-income[5] non-CAP customers, regardless of whether they have an unpaid balance. Customers with an unpaid balance also receive information about assistance programs and the multiple pre-disconnection notices and contacts as described earlier in my rebuttal testimony. Finally, with regard to security deposits, and as discussed above, customers who are verified LMI ≤ 250% of FPL are excluded from being assessed a deposit.

16. Q. Please summarize Ms. Marx's recommendations concerning maximum CAP credits.

A. Ms. Marx argues that PECO should recognize all maximum credit exemptions identified in the Commission's CAP Policy Statement. She further recommends that PECO notify customers earlier that they are approaching their maximum credit and that the notification letter include information about when the maximum credit will expire, how to access LIURP, and information for Rate R customers that may be using electric heating. Finally, Ms. Marx recommends that PECO evaluate all households reaching the max credit by the eleventh month or earlier for LIURP and adjust the max CAP credit amounts with adjustments in the Price-to-Compare ("PTC").

[5] An unconfirmed low-income customer is a customer that has provided a verbal statement of income but has not provided physical documentation of income.

17. Q. Do you agree with Ms. Marx's proposal to recognize additional exemptions to the maximum CAP credits?

A. No. As an initial matter, the CAP Policy Statement (52 Pa. Code § 69.265 (3)(vi)) states that a utility *may* exempt a household from CAP credit or consumption limits if one or more of the following conditions exists: (1) addition of a household member; (2) serious illness of a household member; (3) energy consumption beyond the household's ability to control; (4) housing that is condemned or has housing code violations that negatively impact energy consumption; or (5) energy consumption estimates based on a previous occupant. PECO currently has a health usage rider in place to address the serious illness of a household member. Specifically, the health usage rider exempts a customer from maximum CAP credits when more than 100 kWh per month of electric consumption is needed for life sustaining equipment (e.g., an oxygen concentrator).

The Company does not believe that exemptions are warranted for the other four conditions listed in the CAP Policy Statement. First, if a customer experiences the addition of a household member, they can contact PECO to reverify their income and household size to determine if they qualify for a lower PIPP[6] amount and a potentially higher annual maximum CAP credit amount if their updated FPL places them in a lower FPL tier. Second, CAP customers with high usage can request to participate in PECO's LIURP program, its Energy Efficiency programs, Act 129 and Safe and Efficient Heating Program ("SEHP"), and/or apply for

[6] PECO's CAP is structured as a Percentage of Income Payment Plan or "PIPP."

LIHEAP. Even in the absence of a customer request, PECO transmits CAP customer information to its LIURP vendor on a monthly basis, including information about which customers have reached 75% or more of their maximum CAP credit, to assist the vendor with prioritizing high-usage customers. Third, PECO does not believe that housing code violations warrant unlimited CAP credit amounts. Housing conditions should be addressed primarily by the property owner, such as the landlord or customer. Finally, the exemption for consumption estimated based on a previous occupant does not apply to PECO's CAP. A customer's PIPP credits and annual maximum thresholds are based on current usage, rate, and FPL, not estimates of a previous occupant's energy consumption.

18. Q. Do you support Ms. Marx's proposals to change the timing and content of the notification letter and to evaluate customers approaching their maximum credit for LIURP?

A. No. The timing of PECO's notification letters (at 75% and 90% of a customer's maximum credit) was approved by the Commission as part of PECO's USECP and the overall content of the letters was reviewed by the Commission's Bureau of Consumer Services. I also note that PECO could not accurately forecast exactly when a customer's annual maximum credit will expire because the value of a customer's PIPP credits vary from month to month based on factors such as weather and the customer's consumption behaviors.

Further, as explained above, PECO already directly provides its LIURP vendor with information about high usage CAP customers for review every month. Per the LIURP regulations, PECO's focus is on customers with the highest need

where LIURP assistance can maximize potential bill savings.[7] If a customer has used 75% of their available credits since their last annual maximum reset, that customer will have already been included in a list provided to the LIURP vendor for review.

19. Q. Do you agree with Ms. Marx's recommendation to adjust maximum CAP credits when the PTC is adjusted?

A. No. PECO's Commission-approved USECP already addresses how and when maximum CAP credits should be updated based on changes in distribution rates. PECO believes that Ms. Marx's proposal to adjust the maximum based on the PTC would create confusion for customers, be potentially detrimental to the customer, and result in increased costs associated with IT and process changes that would be needed to implement such a complex requirement. PECO currently updates the residential PTC four times per year. If Ms. Marx's proposal were implemented, a customer's maximum CAP credit amount would also change four times a year. This could make it difficult for a customer to understand their progress towards the maximum and plan financially for exceeding or remaining within their maximum. A quarterly adjustment would also add an additional layer of complexity for the Company if they were required to attempt to forecast when customers would reach their maximum, and require duplicative communications as customers may hit their 75% and/or 90% annual maximum limit multiple times within the same annual period.

[7] *See, e.g.,* 52 Pa. Code § 58.10(a)(1) (priority for receipt of program services is for eligible customers "with the largest usage and greatest opportunities for bill reductions relative to the cost of providing program services…").

20. Q. City/PEA witness Lankenau states that the City and others would benefit from "improved reporting" of Universal Services data and recommends that PECO initiate regular stakeholder meetings with the City and others to discuss data collection needs and the communication of data. Please respond.

A. As Ms. Lankenau acknowledges, PECO already reports a range of Universal Services program data to the Commission and PECO-specific information is available in a variety of PUC reports. PECO also conducts quarterly USAC meetings with its USAC members which include Utility Emergency Services Fund ("UESF") and Energy Coordinating Agency ("ECA"), both are organizations supporting our most vulnerable customers in the City of Philadelphia, providing grant support to customers having trouble paying their utility bills and supporting those customers seeking heating system repair, home weatherization to save energy, utility bill assistance, energy conservation education, and connections to a wide range of services across the City. At those meetings, PECO provides a detailed overview of assistance programs including CAP, LIHEAP, LIURP and MEAF performance, providing data on customers served, amounts spent on individual programs, and other metrics. Separately, PECO also engages with its USAC members to discuss issues of interest and communicate other key information. PECO does not believe that changes are needed to its dual tracks of formal reporting and responding to informal inquiries of stakeholders.

21. Q. City/PEA witness Schapira expresses concern that participation in the City's "Solar for All" program may conflict with mutually participating in CAP.

Please respond.

A. PECO customers may simultaneously participate in CAP and "Solar for All." PECO has been actively collaborating with PEA and others on the implementation of this program, including coordinating the program with PECO's Universal Service programs. If a CAP customer participates in "Solar for All," and either owns or leases solar panels on their premise, they will receive an offset in their billed usage and will pay the lesser of their PIPP bill amount or the actual usage amount, subject to a minimum bill amount. The usage offset will benefit the CAP customer by reducing the PIPP credits applied each month and slowing the customer's utilization of their maximum annual CAP credit allotment.

B. <u>LIURP</u>

22. Q. Ms. Marx is critical of PECO's LIURP job completion rate, spending per job and service of tenants. She recommends that PECO: (1) increase its LIURP budget by $4,400,000 to about $10,000,000; (2) revise its high usage eligibility threshold to account for usage on a per square-foot basis; (3) improve direct solicitation to high usage CAP customers; and (4) provide reports to USAC about (i) barriers and solutions regarding tenant issues and (ii) barriers and solutions regarding coordination with other home repair and weatherization programs. Please respond.

A. At the outset, I would like to clarify that PECO's current electric LIURP budget is $6.6 million, so a $4.4 million increase would bring the total electric LIURP budget to $11 million. I further note that PECO is actively participating in the

Commission's LIURP Notice of Proposed Rulemaking ("NOPR") proceeding[8] and has filed comments regarding the Commission's efforts to update the LIURP regulations. To the extent Ms. Marx has programmatic LIURP recommendations, they would be more appropriately raised in the NOPR proceeding.

Turning to the specific criticisms, I disagree with Ms. Marx that the success of PECO's LIURP can be measured by looking at individual statistics in isolation. Each LIURP participant household is evaluated and measures are implemented if they meet LIURP requirements, including certain payback period requirements as defined in the LIURP regulations.[9] The spending per household is a function of what measures are appropriate in the homes we evaluate in a given year. The number of jobs completed in a year is also dependent upon a number of factors, including how many measures are being installed, and their costs, in each premise. We continue to focus on assisting high usage customers and installing measures that will maximize energy saving benefits.[10] Importantly, since the removal of COVID restrictions, PECO has been expending its full LIURP budget for the benefit of customers. Over the years we have consistently increased the LIURP budget and believe the current budget is appropriate. Just last year, the LIURP budget was increased by $1 million for electric service and $0.9 million for gas service. These increases, along with dedicated Health and Safety spending

[8] *See* Docket No. L-2016-2557886.

[9] *See, e.g.,* 52 Pa. Code § 58.11 (establishing payback periods applicable to LIURP measures).

[10] Notably, the energy savings resulting from LIURP jobs has increased significantly. The latest APPRISE LIURP Evaluation Final Report completed in 2024 for 2022 found that: (1) savings from electric heating jobs averaged 10.5%, compared to recent years that had savings below 6%; and (2) savings from gas heating jobs were 7.2% compared to recent years that were all below 5% and often below 3%. *See* PECO Exhibit JFG-1 for a copy of the APPRISE LIURP Evaluation Final Report.

($1.5 million for the permanent electric program and $100,000 for the gas pilot expiring at the end of 2025), brings PECO's LIURP spending to approximately $11.4 million annually.

Second, PECO does not have, and has no feasible way of collecting, the square footage of each customer premise in advance of a LIURP audit in order to deploy the type of usage per square-foot threshold recommended by Ms. Marx. PECO notes that Act 129 can provide electric energy efficiency support for low-income customers who reside in smaller dwellings and do not meet LIURP's usage threshold. Similarly, on the gas side, certain low-income customers with lower total usage but higher usage per square-foot can access no-cost measures through the SEHP. In addition, in response to Ms. Marx's comments on barriers to tenants, PECO does work with customers who are renters to minimize barriers. If a customer is a renter, the LIURP contractor will contract with the property owner and provide a consent form and self-addressed postage paid envelope. The contractor will follow-up for receipt of the consent form before the work begins. Consent from the owner can also be obtained verbally over the phone on a recorded line. A letter shall be delivered to the customer and property owner confirming that consent has been obtained.

Regarding the final recommendation about reporting to the USAC on various LIURP issues, PECO already appropriately engages the USAC and program partners. In addition to regularly sharing LIURP information, PECO conducted two multi-family collaboratives (one in 2022 and one in 2023) with a range of stakeholders, including the OCA, Community Legal Services, and the Public

Utility Law Project.[11] During the collaborative, the Company discussed how PECO could support all types of dwellings by utilizing LIURP and its energy efficiency and conservation ("EE&C") programs. PECO also collaborates with the PEA and its Built to Last Program ("BTL") by accepting direct referrals from BTL for PECO's Act 129 EE&C low-income programming. Eligible customers are scheduled for a free energy checkup and measures are provided to the customer at no cost.[12]

C. MEAF

23. Q. Ms. Marx recommends that: (1) MEAF grant amounts be increased to $1,000 for baseload electric service with an additional $1,000 for heating customers; (2) MEAF funds be distributed proportional to low-income populations in each county; and (3) PECO replace MEAF's zero balance requirement with a requirement that a grant be sufficient to "resolve the crisis." Do you agree with these recommendations?

A. I do not. PECO continues to believe that the Company's proposal to change the maximum allowable MEAF grant from $500 per commodity to $1,000 per account is appropriate. This change should allow additional customers to meet the MEAF eligibility criteria of bringing the customer's account balance to zero by permitting all eligible customers (regardless of service type) to qualify for a MEAF grant of up to $1,000. Fundamentally, the MEAF program is an

[11] The collaboratives were held in accordance with a Commission-approved settlement in PECO's most recent gas base rate proceeding (Docket No. R-2022-3031113).

[12] In discovery response cited by City/PEA witness Schapira (pp. 11-12), PECO interpreted "coordination" as PECO LIURP either working on the same project or paying for components of a BTL job as was requested during the BTL pilot.

emergency program to help customers avoid termination, and an increase in grants for higher balances will provide assistance to fewer people.

Regarding the distribution of MEAF funds, as I explained in my direct testimony, PECO already distributes any funds for which it has not received a customer match – up to $300,000 annually – to the MEAF agencies in proportion to the number of low-income customers in each county within PECO's service territory. The distribution of these remaining funds to the agencies then becomes available as a contribution for the agency to use as their portion of the grant, to be matched by an additional PECO shareholder contribution per the normal MEAF process, thereby increasing the funds available in the counties for future application to customer accounts. Finally, PECO does not believe the zero-balance requirement should be waived because MEAF is not intended to be a supplemental grant program, but rather a means to address collections risk by achieving a zero balance.

24. Q. Please summarize Ms. Marx's recommendations concerning MEAF grant availability and oversight of MEAF agencies.

A. Ms. Marx identified some grant issuance delays by PECO's MEAF agency in Philadelphia County – the UESF – and generally expressed concern about the number of grants issued and the underspending of available funds. She recommends that: (1) PECO monitor the performance of each MEAF agency including requiring monthly reports from each agency; (2) PECO file monthly reports on the status and availability of MEAF; and (3) MEAF operation issues be

referred to the Commission's Bureau of Audits and Bureau of Investigation and Enforcement.

25. Q. Do you agree with her recommendations?

A. I believe that PECO already has sufficient processes in place to monitor MEAF agency activity. On a weekly basis, PECO reviews MEAF grants received and posting of matching PECO shareholder contributions. On a monthly basis, PECO reviews invoices from MEAF agencies to track and confirm each agency's activity. PECO also hosts quarterly USAC meetings where MEAF agencies attend and have the opportunity to address issues and answer questions. The Company does not believe that MEAF implementation issues warrant investigation by the Commission because: (1) the Company's issues were temporary and have been resolved; (2) PECO has implemented continuous monitoring of UESF; and (3) PECO will affirmatively communicate significant issues with a MEAF agency to the Commission's Bureau of Consumer Services ("BCS") and provide them with status reports as appropriate.

III. OFFSET FACTORS IN THE UNIVERSAL SERVICE FUND CHARGE

26. Q. Have any parties opposed PECO's proposal to change the offset factor applied to reconcilable CAP costs recovered through the USFC from 27% to 10.5%?

A. Yes. Mr. Colton contends that PECO's proposal to lower the bad debt component of the USFC offset factor from 22% to 5.5% based on the difference between the three-year average (2021-2023) uncollectible rate for CAP customers and all residential customers artificially reduces the offset factor. Mr. Colton makes

some additional contentions regarding the cash working capital offset which are addressed in the rebuttal testimony of Mr. Trzaska.

27. Q. Does Mr. Colton dispute that the difference between the three-year average uncollectible rate for CAP customers and all residential customers is a reasonable methodology to determine the offset (positive or negative) to PECO's bad debt expense arising from incremental changes (increases or decreases) in CAP enrollment levels?

A. No. However, Mr. Colton contends that using 2021 in the three-year average is unreasonable since PECO's rate of net charge-offs was abnormally low in that year due to the impact of the COVID-19 pandemic on customer collections activities.

28. Q. Is PECO making any changes to its proposed update to the bad debt adjustment in the USFC formula to address Mr. Colton's concerns?

A. Yes. PECO proposes removing 2021 from the three-year average rate of net write offs in the calculation described in my direct testimony. As shown in Table 1 below, using a three-year average for calendar years 2019, 2022 and 2023 produces a bad debt offset percentage of 7.1%, which is 1.6% higher than PECO's original proposal.

Table 1

	CAP Customer Billings vs Net Charge-Offs				All Residential Customer Billings vs Net Charge-Offs			
	2019	2022	2023		2019	2022	2023	
Annual Billings ($M)	$102.0	$118.7	$94.3	3-Year Average	$2,331.4	$2,861.1	$2,868.7	3-Year Average
Net Charge-Offs ($M)*	$7.2	$10.3	$7.7		$14.8	$28.9	$34.2	
Ratio (%)	7.0%	8.7%	8.2%	**8.0%**	0.6%	1.0%	1.2%	**0.9%**

*Excludes October 2016 one-time In-Program Arrearage ("InPA") forgiveness and Pre-Program Arrearage ("PPA") forgiveness.

IV. RESIDENTIAL CUSTOMER ISSUES

29. Q. Mr. Colton contends that PECO has no claim for "exemplary management" in the area of (1) Universal Service and (2) credit and collections performance, citing CAP enrollment numbers and payment arrangement and disconnection statistics for low-income customers, and the level of residential arrears. He further argues that PECO does not appropriately query customer satisfaction or utilize technology to enable assistance with program enrollment. Please respond.

A. I believe we have provided extensive support for PECO's exemplary management performance. In light of Mr. Colton's testimony, however, I want to highlight several areas where we have provided substantial assistance to the low-income customers we serve.

- In July of 2022, PECO incorporated the updated energy burdens in the CAP Policy Statement and then converted the structure of its CAP to a PIPP in December 2022. Overall CAP bill credits to customers increased by approximately $27 million for electric and gas from 2021 to 2022. Additionally, in 2023, the first full year of the PIPP, CAP customer bill credits increased by approximately 64% for electric service (from $86 million in 2022 to $140.7 million) and more than 100% for gas service (from $5.3 million in 2022 to $10.9 million). While CAP enrollment varies throughout the year, it has remained relatively consistent over the last several years averaging approximately 122,000 customers since 2021. As evidenced by our CEOP, PECO is focused on outreach to customers

who are in need of financial support while also ensuring that customers enrolled in CAP remain eligible through requiring income recertification so that more program funds are available for those most vulnerable. In addition, as discussed earlier, PECO has recently increased its LIURP budgets.

- PECO's termination procedures and other credit and collection processes are applied equally to all customers and PECO does not target specific zip codes or classes of individuals. PECO's credit and collections activities are focused on reducing arrears and annual write-off amounts. While it is not our objective to terminate customers for nonpayment, terminations are necessary to support the objective of reducing the arrears and write-offs for all customers including verified low-income customers <250%, who represented ~22% of terminations in 2023. In regard to payment arrangements, PECO provided approximately 78,000 payment agreements in 2023.
- As I have already explained, we are conducting hundreds of outreach events to increase enrollment every year, and we are succeeding at ensuring that our low-income customers have sufficient assistance as well as access to a range of programs that can help them save energy.
- We process applications in a timely manner and provide a range of enhanced communications to assist customers with recertification as well as obtaining "retro" reinstatement credits for up to 12 months in which they may not have been on our CAP program due to a failure to recertify.

- The Company is utilizing technology to assist customers in connecting with assistance programs. In fact, as stated previously in my testimony, customers can submit CAP enrollment information online via PECO.com, noting that information explaining the program is provided in English, Spanish and Simplified Chinese. In addition, PECO's Assistance Finder provides customers with information on where they can go to apply for various programs including CAP, which makes the available online CAP application easier to access and therefore improve the enrollment experience for the customer. The Company also includes on our website the link to the DHS's Compass website where customers can apply for LIHEAP.

Finally, PECO collects information about the level of customer satisfaction of LMI customers. A third-party vendor surveys residential customers (by phone and digitally) after customer interactions with PECO. In addition to collecting information about customer satisfaction, those surveys ask customers to provide income information. Based on the survey responses, customer satisfaction improvement plans are developed to address themes of opportunity identified.

30. Q. Mr. Colton contends that PECO should amend its tariff Rule 17.4, Payment Processing to permit dual customers to designate that all or part of their combined PECO bill payment be applied to electric service –including past due balances and current charges –before being applied to natural gas service, or vice versa. Does PECO support the implementation of these recommendations?

A. No. PECO provides customers who receive electric and gas service with a total bill for their utility service, not one for gas and one for electric. There is no basis for permitting customers to "prefer" one service over another, and a customer in arrears is at risk for termination of both services.

31. Q. Ms. Marx makes several recommendations related to language access, including that PECO should: (1) track the primary language of its customers as part of its customer information system; (2) send residential bills (or key portions thereof) and residential termination notices in English and Spanish to all households; and (3) include a tagline about interpretation service in five languages on residential customer bills and termination notices. Does PECO agree with these recommendations?

A. No, PECO believes that its existing processes to address language access issues are appropriate and meet or exceed Commission requirements. Implementing Ms. Marx's proposals, including the proposed software upgrade for tracking a "primary" language of customers, would create new costs that PECO does not believe are warranted at this time.

With respect to written documents, PECO's current collection notices already include a sentence in Spanish alerting customers that the notice is important and that they should contact the Company for help if needed. Similarly, PECO's bills include a sentence in Spanish explaining how a customer can contact PECO if they have questions or concerns. When an LEP customer contacts PECO, they have access to translation service in over 100 available languages. PECO provides its CAP and LIHEAP applications in English and Spanish (in PDF format on

PECO's website and in hard copy at outreach events). PECO also provides our low-income program brochure in English and Spanish.

Furthermore, for low-income outreach events in Spanish-speaking areas / zip codes, PECO provides representatives fluent in spoken and written Spanish to conduct those events. For non-Spanish speaking LEP outreach events, PECO provides interpreters upon request. Those interpreters are typically members of LEP organizations with whom PECO partners. PECO provides documents such as assistance program brochures, the CAP application, the LEP language line card, and website translation assistance to community-based organizations and our customers in various languages.

32. Q. Please summarize Ms. Marx's recommendations regarding the determination of residential heating type.

Ms. Marx recommends additional customer touchpoints to determine if a customer is properly on Rate R or Rate RH, such as when a new customer account is opened, during LIURP audits, when a Rate R customer is approaching their CAP credit maximum, and when a Rate R customer has high winter usage. She further recommends revisions to tariff language to allow customers to enroll in Rate RH if they rely on electric heating equipment as a primary or supplementary heating source.

33. Q. Does PECO support the implementation of these recommendations?

A. No. Customers indicate their heat type when submitting a service and meter application, either at the time of a new connection or when they are applying upon an upgrade to existing service, which could be when they are upgrading from a

different fuel type to electric heat. If a customer or advocate contacts PECO to inform us that the customer has installed primary electric heating equipment consistent with Rate RH requirements, the Company will switch the customer to Rate RH upon verification based on their documentation of the equipment installed. High usage in the wintertime does not necessarily indicate electric heating and therefore does not warrant additional outreach requirements.

In addition, for high bill disputes, we have a care center process in place where we take information from the customer regarding a potential rate change, and if the customer appears to qualify, they submit information via email to PECO for review. Finally, PECO does not agree with a revision to the tariff language to allow customers to enroll in Rate RH if they rely on electric heating equipment as a supplementary heating source. I note that Rate RH is not designed to facilitate customer use of space heating in light of the cost and safety hazards of such equipment.

34. Q. Please summarize Mr. Colton's recommendations concerning processes related to residential security deposits and disconnections.

A. Citing the potential for discriminatory effects, Mr. Colton argues that the Commission should mandate additional review of certain PECO processes. First, he recommends that PECO's risk analysis methodology underlying its disconnection of service and cash security deposits should be subject to a public review by the Bureau of Consumer Services and stakeholders. Next, he argues that PECO should conduct a root cause analysis to determine and address the cause of an alleged "disproportionate" level of disconnections in certain zip codes

with relatively greater numbers of Black households. Finally, Mr. Colton recommends that PECO's Tariff be modified to state that its credit scoring methodology "does not directly, or have the effect of, discriminating based on a protected class as set forth in the federal Equal Credit Opportunity Act."

35. Q. Do you support Mr. Colton's proposals?

A. No. PECO's termination procedures, credit scoring, and other processes are applied equally to all customers and PECO does not target specific zip codes or classes of individuals. PECO's risk assessment procedures that are used to determine whether and/or when to schedule a disconnection of service to a residential customer for nonpayment are based on PECO's goal to improve its collection activities, decrease its annual write-off amounts, and reduce the overall cost of field collections activities. Factors used in the risk assessment include account balance, monthly bill amount, probability of cut success, percentage of balance paid if cut, percentage of balance paid if not cut, probability of account finaling if cut, and probability of account finaling if not cut. PECO does not know, nor does it track, customers by demographics such as race or ethnicity for purposes of disconnection.

I note that PECO partners with assistance organizations to identify and implement initiatives to remove barriers for underserved communities to access federal, state and local energy assistance funding. PECO contracts with 30 community-based organizations strategically located throughout PECO's entire service territory. These agencies are trusted by the communities they serve and PECO's affiliation with these organizations only serves to expand our outreach. Additionally, PECO

provides training to agency workers to ensure each agency is aware of PECO's comprehensive suite of assistance programs to maximize assistance options for LMI customers.

V. LARGE CUSTOMER ACCOUNT MANAGEMENT AND BILLING ISSUES

36. Q. City/PEA Witness McGraw alleges that PECO has trouble executing routine requests such as turning on electricity for new meters and responding to billing questions despite regular follow-ups." Do you agree?

A. No. PECO has assigned an Account Manager ("AM") that is dedicated to working directly with the City on all matters. The PECO AM is the primary point of contact for more than twenty (20) City departments including, for example, Streets, Parks and Recreation, Water, and License and Inspection. The AM directly supports or coordinates within PECO most of the inquiries from these departments and ensures seamless communication and excellent customer service. The PECO AM is available to receive the City's questions and concerns on a 24/7 basis, meaning that the City can connect with the PECO AM at any time during the day or the night. In addition, the PECO AM has an assigned "back-up buddy" to assist the City when the PECO AM is not otherwise available. In addition, each large customer, including the City, is provided with an toll-free number that rings to the on-duty shift manager in case of more urgent after-hours needs.

The City's designated PECO AM has the primary responsibilities delineated below.

1. ***Consolidation, review and distribution of monthly invoices for all of these departments within the City***. This includes ensuring billing accuracy and

promptly addressing any discrepancies.

2. ***Receive and review all new service requests from City departments***. This involves coordination with various internal teams to assess the feasibility, plan the service implementation, and ensure timely delivery.

3. ***Collaborate with the City's internal teams, such as regional engineering and billing, to resolve any customer concerns***. This collaboration is crucial for addressing technical issues, ensuring accurate billing, and maintaining high customer satisfaction.

4. ***Serve as the emergency contact for addressing outage related concerns after hours and during weekends***. The PECO AM works directly with the outage control center to ensure swift resolution of any power outages or disruptions to minimize the impact on City operations.

5. ***Attend monthly check-in meetings with the Office of Sustainability.*** During these meetings, the PECO AM addresses any open requests or issues related to sustainability projects and energy usage, ensuring alignment with the City's sustainability goals. The PECO AM also attends scheduled meetings with the other departments as requested by the City.

6. ***Provide support to the City's sustainability efforts by gathering and providing relevant information***. This includes data on energy consumption, efficiency measures, and other sustainability initiatives. The PECO AM also ensures that the City has the necessary information to make informed decisions to meet its sustainability targets.

Regarding concerns related to executing routine requests expressed in Mr.

McGraw's testimony, I note that PECO has defined procedures and practices in place that require information to be obtained prior to energizing a new service, stopping a service, and making sales tax and billing changes. The City's account is complex and has numerous touchpoints and resolution of specific issues often requires feedback from and communication with the City as well as their various contractors who submit these requests. However, while PECO's resolution of specific requests can take time to review, coordinate and implement given the intricacies of the City's account, PECO makes every effort to respond to all requests in a timely fashion.

With specific respect to the City's billing questions, historically, the PECO AM would research the question at hand and take the appropriate actions to address the issue. These actions can range from providing a billing explanation to submitting requests to the billing department to update and/or revise the bill. In the instance of the need to issue a new bill reflecting required changes, the new bill would be generated during the next billing cycle, where it is once again reviewed for accuracy by the PECO AM. It should be noted that the City, in addition to its numerous departments, has multiple contractors that also coordinate with different departments within PECO (in other words, not just the AM) specifically to make requests for starting and stopping service. Not surprisingly, these additional interactions can further complicate the City's account. Despite this, the PECO AM remains in constant communication with the City and provides timely updates on existing known issues or captures newly identified issues, at each standing monthly check in meeting, as well as during the

many ad-hoc follow up calls and meetings.

In response to Mr. McGraw's comments regarding availability of account numbers after the billing system transition, PECO notes that implementation of the new billing system, customers were directed to utilize an online look up tool or wait to see their new account number on the first bill generated from the new system. After implementation of the new billing system, PECO created a customized solution for the City to access new account information by providing it with an excel spreadsheet containing a comprehensive list of all the City's old and new account numbers as well as other relevant account information. If PECO had not provided this information, the City would have had to manually look up each account number one at a time using the on-line tool or wait until it received the first bill generated from the new billing system to retrieve new account information.

In addition, during conversations with the City over the past few months, the PECO AM has informed the City that PECO is continuing to address billing exceptions that may impact the City, such as the bill presentment issue mentioned by Mr. McGraw, and will continue with its process of providing regular updates when available as we work to resolve any outstanding exceptions they may have.

37. Q. Mr. McGraw testifies that the City has faced difficulty working with PECO on its LED streetlighting project as it relates to PECO's response to questions about PECO-owned equipment on poles. Can you please provide an update?

A. I do not believe that this is an outstanding issue.

The City informed PECO that it faced challenges getting information related to PECO equipment attached to the City's streetlight poles. At the initial meeting, which took place on October 12, 2023, the City stated that it encountered ten (10) devices that were attached to its streetlight poles while it was completing the first thirty thousand (30,000) installations of LED lights and asked PECO for direction on how to remove them. At the time, PECO assumed that the devices had most likely been abandoned in place in 2017 and would be removed by PECO when the opportunity presented itself during routine maintenance on PECO equipment. PECO reviewed the matter and confirmed to the City that they would work with the City to determine a process to remove the devices.

PECO had to then determine who was responsible for the cost of removal and what field personnel would remove the devices (e.g., PECO or the City's contractor). The City's contractor cost for removal was four times PECO's cost of removal. After internal review and coordination with the City, PECO agreed to remove the devices at PECO's cost. However, when PECO sent personnel out to remove the ten (10) devices, only seven (7) devices were discovered and of those seven (7), only five (5) of them were PECO devices. PECO removed the five devices and notified the City of the status. PECO also agreed to utilize the "City Works" portal (the City's preferred method of communication) to obtain appropriate information if the City should discover other PECO devices in the future. In addition, moving forward, the City and PECO agreed that PECO crews will remove any devices from the city-owned streetlight poles at PECO's cost.

38. Q. Mr. McGraw also takes issue with and provides examples of administrative

issues related to PECO's implementation of a new billing system in February 2024. Can you provide an update regarding resolution of the City's billing issues?

A. Prior to implementation of the new billing system, PECO met regularly with its large customers, including the City, to discuss the implementation timeline and related administrative matters and since implementation, PECO has been in frequent contact with the City.

With respect to the specific issues Mr. McGraw references, PECO has resolved four of the five issues and is currently working to resolve the remaining outstanding issue related to bill presentment. We will continue to provide updates to the City as soon as they are available.

39. Q. How do you respond to Mr. McGraw's recommendation to "establish service-level agreements ("SLAs") for requests handled by account managers, both for routine billing questions as well as requesting surrounding sustainability project" to ensure customer needs "are being met in a timely manner"?

A. PECO believes that large customer needs, including those of the City's, are being met on a timely and consistent basis. Before responding directly to Mr. McGraw's recommendation to establish an SLA between PECO and the City, I want to highlight the direct testimony submitted by Lisa V. Perry on behalf of Walmart, Inc., another large PECO customer. Specifically, at pages 23-25 of her direct testimony, Ms. Perry commends PECO for establishing a "key account management team dedicated to engaging with and addressing the unique needs of

its larger customers" and provides detailed testimony about the importance of the relationship between the account representative and the large customer so to "inform the Commission of the valuable service provided by the Company's key account management team."

In responding to Mr. McGraw, I note again that, as with Walmart, due to the size and complexity of its account, the City receives a highly customized, premier level of service with a designated 24/7 PECO AM that is responsible for being the point of contact for the City's customer service needs, including manual consolidation, review and distribution of monthly invoices for the more than twenty (20) departments within the City.

Also, as discussed above, the PECO AM ensures the City's needs with respect to sustainability efforts are being met by gathering and providing relevant information with the support of other internal stakeholders and attending monthly check-in meetings with the City's Office of Sustainability. This information includes but is not limited to providing data on energy consumption and efficiency measures which allows the City to make informed decisions and meet its sustainability targets.

For these reasons, PECO does not believe that an SLA is necessary given the personalized customer service that the City enjoys today by virtue of having a single point of contact to coordinate and facilitate resolution of its customer service requests.

40. Q. The testimony of SEPTA witness Crist raises similar concerns with respect to account management and billing issues for large customers and testifies that

"[t]hese have all been relayed to PECO but there has been no follow up on confirmations of the timing for resolution." How do you respond to this statement?

A. As with the City, PECO met with large customers, including SEPTA, before implementation of the new billing system to discuss changes and timelines, and we have been in frequent contact throughout the process. In fact, in his direct testimony, Mr. Crist provided a copy of the notification in October 2023 PECO provided regarding the transition to the new billing system in 2024.

In addition, after implementation, the PECO AM for SEPTA has had regular meetings and multiple phone calls with the SEPTA Management Analyst regarding billing exceptions, including bill presentation and summary bill. Resolution of exceptions is a top priority for PECO and we are working diligently to resolve any outstanding issues, including invoice delivery and confirmation of account additions and deletions from SEPTA's billing. PECO continues its commitment to keeping SEPTA fully informed throughout the resolution process.

41. Q. Mr. Crist also raises concerns regarding the Company's customer portal and the removal of information regarding Installed Capacity ("ICAP") and Network Integration Transmission Service ("NITS"), "which are important data for customers that receive electric commodities from third party suppliers" because the data allows them "to verify if they are being invoiced correctly and with the correct billing variables." Mr. Crist goes on to recommend that PECO resume providing access to ICAP and NITS data on the portal, including interval data. What is your response to this

recommendation?

A. First, with respect to Mr. Crist's concerns related to the removal of account-level ICAP and NITS transmission tags on the customer portal, I note that the decision to remove customer access to that information was made by PECO security in response to an increase in cybersecurity attacks among large companies and is unrelated to the implementation of PECO's new billing system. PECO felt it was prudent to take proactive measures to protect our customers and their employee account information from these growing threats.

Second, billing variables such as ICAP and NITS transmission tags are available to customers upon request. In fact, SEPTA's PECO AM has provided SEPTA's consultant with ICAP and NITS tag information. Currently, PECO's information technology and business departments are working to identify a solution to resume direct accessibility by customers and will keep SEPTA updated accordingly. Finally, as for Mr. Crist's recommendation regarding interval data, this past May, PECO started work to integrate our third-party portal, which provides interval data for large commercial and industrial customers, with the new billing system. We are now in the second phase of this project and anticipate that the new portal will launch later this year and provide improved access of information for our customers.

VI. CUSTOMER SERVICE AND SATISFACTION

42. Q. In his testimony, OCA witness DeMarco notes customer service improvements the Company has made with its website and Mobile App and increased enrollment in "My Accounts" for both PECO Gas and PECO

Electric but expresses concern that the Company does not identify the cost savings associated with these improvements.

A. The "My Accounts" enrollments for both the website and mobile app have increased for residential customers. However, since this technology offering is relatively new to customers, it is premature to quantify cost savings associated with this improvement. It is important to note that this technology is designed to facilitate an improved customer experience and ease for customer of access to customer account information, and an overall cost savings may be difficult to quantify.

43. Q. Do you agree with Mr. DeMarco's recommendation to implement a "two-step identification" process to protect customer account information?

A. I disagree with Mr. DeMarco's recommendation to implement Two-Step Identification because the process is already a part of our customer security protocol. Voluntary Two-Step Identification went live as part of our offering in the first quarter of 2022. Mandatory Two-Step Identification for new residential customers is scheduled to go live by the end of 2024 and for all residential customers in 2025.

44. Q. Mr. DeMarco claims that the Company has made inconsistent statements about whether the improvements and costs savings associated with the website and the Mobile App form the basis for its request for a management performance adder and requests clarification in rebuttal. Can you please respond?

A. I disagree that the statements are inconsistent. For example, as Ms. LeVine testified in her direct at page 26, lines 5-12, the Company added "other features and capabilities" to the PECO website. In response to OCA-16-3, Ms. Levine answered "no" as to whether her discussion of the added "features and capabilities" supported the management performance adder. While the new "features and capabilities" alone do not support the management performance adder, the success in terms of customer efficiency and support that has been achieved through the Company's proactive implementation of the additional "features and capabilities" that were identified in Ms. LeVine's direct testimony contributes to the Company's recommended addition of fifteen (15) basis points to the allowed return on equity for management performance.

45. Q. Please summarize Mr. DeMarco's concern about the Company's plan to improve customer satisfaction.

A. Mr. DeMarco states that the Company fails to define its objectives or provide support for how it plans to reach its objectives. He further alleges that the Company has not performed a cost-benefit analysis or identified any goal metrics to assess results. He states that a management performance adder is appropriate only once those improvements are in place.

46. Q. How do you respond to his concern that the Company did not define its objectives or providing support for how it plans to reach its objectives?

A. PECO's plan to improve customer service begins with routine customer satisfaction surveys administered by a third-party vendor throughout the year. PECO's third-party vendor will randomly select residential customers and contact

them either by phone or email to solicit feedback on various customer service topics. For commercial customers, the vendor reaches out directly by phone to discuss PECO's level of customer service. After PECO receives and studies the survey responses, the Company takes action to implement solutions to address any concerning feedback provided by the customers. As an example of actions taken, in 2023, PECO enhanced the promotion of digital adoption, which increased the web activity for billing and payment options. The Company also sent out 3.1 million emails to educate customers about price-to-compare and created an animated video about third-party suppliers for additional education. Moreover, in response to survey feedback from small and medium business customers, PECO assigned account managers (just like the ones assigned to the large customers). As a result, PECO has created more touch points with this customer class and our outreach has increased significantly.

In 2024, PECO continues to focus on improving customer satisfaction by strategically communicating with customers to promote self-service tools including My Account and e-bill. PECO has developed a new self-service video to explain how to use the new tools, and is currently developing a new *'Understanding Your Bill'* customer video. The self-service offerings allow customers to do business with the Company when it is convenient for them, which is often after regular business hours and on the weekend. I can report that we are seeing positive results. For example, self-service adoption grew approximately 22% between 2022 and 2023 (from 5.3 million users to 6.5 million users) with utilization of the Company's self-service offerings increasing nearly 21% between

2022 and 2023.

Finally, as I discuss in more detail below, PECO is focusing on the CSR component of customer satisfaction as evidenced by the "Universal Agent" training.

47. Q. Do you agree with Mr. DeMarco assessment of the Company's plan to improve customer satisfaction?

A. No. I disagree with Mr. DeMarco's assessment of the Company's plan to improve customer satisfaction primarily because the Company has identified strategies to improve customer satisfaction year-over-year. Such strategies include using targeted communications to promote self-service tools and services available to customers including MyAccount and e-bill enrollments. As noted above, the Company is incorporating new self-service videos in PECO's external outreach and is currently developing a new *'Understanding Your Bill'* customer video. Lastly, the Assistance Finder tool uses technology that helps customers find programs designed to support their specific needs all in one place.

48. Q. Do you agree with Mr. DeMarco that the Company has not supported its claim that customer benefits will come from investment in customer operation?

A. No. The investments implemented to date are designed to improve the availability of customer products and the reliability of the underlying platforms. As I noted above, these projects consist of enhancing digital self-service options and offering personalized solutions that meet customers' needs. One investment to "help promote and improve affordability" is "My Account," which has enabled

customers to navigate more efficiently and utilize online options to manage their individual needs. The use of Assistance Finder tool provides customers with personalized program recommendations to allow them to manage their bills and energy usage and, as mentioned previously in my testimony, helps them find programs designed to support their specific needs all in one place.

VII. CALL CENTER PERFORMANCE

49. Q. Mr. DeMarco recognizes 2023 improvement in PECO's call abandonment rate and average calls answered within 30 seconds but notes that PECO has not reached its goal for the 2022-2025 period. How do you respond?

A. PECO sets aggressive internal targets for the call abandonment rate and the percent of calls answered within thirty (30) seconds to meet customer needs. PECO achieved significant improvements in both call abandonment rate and the percent of calls answered within thirty (30) seconds from 2022 to 2023. While these metrics are important and will continue to be a focus of the Customer Care team, we believe that First Contact Resolution ("FCR") is a better measure of the ease of doing business with PECO. The abandonment rate and the percent of calls answered within thirty (30) seconds are an indication of how quickly calls are answered while FCR is an indication that the customer's issue was resolved on the first attempt. Customer satisfaction research has indicated that resolution of the customer's issue on the first attempt is a higher priority to the customer than short wait times. Our Customer Care team is focused on making improvements in this area.

50. Q. Mr. DeMarco acknowledges the Company's improvement to call center performance through implementation of a FCR approach and a "Universal Agent" strategy. Do you agree with his recommendations to conduct further analysis on how to improve the FCR process and investigate any issues regarding call handling that have not been resolved since the July 2022 Audit Report?

A. No. In fact, prior to the July 2022 Audit Report, upon its own initiative the Company transitioned to FCR and made it a top priority metric for Customer Care. Customer Care has made several changes to enhance FCR since that time, including increasing call evaluations, implementing a new process flow tool for agents, realigning resources within the organization to increase agent coaching support, and investigating FCR by call type to identify opportunities for process improvements. In a sense, the Company has already implemented Mr. DeMarco's recommendation as Customer Care continues to focus on ways to improve FCR.

51. Q. Citing UCARE statistics, Mr. DeMarco notes an increase in the number of customer complaints and verified infractions. He recommends the PECO create a plan with metrics to reduce the level of information complaints and verified infractions. Do you agree?

No. First, let me say that PECO's operations team continually strives to minimize the number of customer complaints and verified infractions, and as I noted above, conducts third-party surveys throughout the year to identify areas of improvement and provide solutions. Second, I believe Mr. DeMarco is incorrect about an increase in the number of residential complaints and verified infractions. If 2021

is excluded from the data – consistent with OCA Witness Colton's argument that 2021 was an atypical year (Statement 4, pages 104-106)) – the results show a decrease in residential complaints and a "remains steady" trend in verified infractions.

Third, I direct Mr. DeMarco to BCS's "Quarterly Update to UCARE Report for January—December 2023" which demonstrates that in 2023 PECO had the lowest residential complaints rate of all Pennsylvania electric utilities (the rate is calculated by the number of complaints per 1000 customers). Specifically, PECO's Volume Rate for residential complaints was 1.0. Likewise, with respect to verified infractions, PECO performed at the top of all Pennsylvania utilities with an Infraction Rate of 0.10.[13] In this regard, the data shows that PECO is leading the way.

For these reasons, I disagree with Mr. DeMarco's recommendation that PECO should conduct a root cause analysis and create a plan with actional metrics providing how PECO will reduce informal complaints and verified infractions.

52. Q. In response to questions about bill payment options and fees, Mr. DeMarco notes discovery regarding fee revenues from transactions (pay as guest and by phone) received from customers had not been received from the Company. Can you provide an update?

[13] Quarterly Update to UCARE Report for January—December 2023, https://www.puc.pa.gov/media/2754/ucare_2023_q4.pdf

A. PECO provided the responses to the interrogatories referenced by Mr. DeMarco in this proceeding on June 14, 2024, and confirmed that the Company does not receive revenues from customer payment fees.

53. Q. Mr. DeMarco expresses concern about the potential for discrimination by charging customers a fee to pay their bill when they are not doing so via My Account or when they pay by phone and recommends that PECO eliminate these fees as a direct cost to consumers. Do you agree?

A. No, I note that PECO offers multiple no fee payment options, including mailing payments directly through the United States Postal Service, submitting an electronic payment (e-check) via MyAccount or the customers' bank or third-party institution, as well as for those customers that have a MyAccount but wish to pay by phone, with agent assisted payments using e-check.

Additionally, while a payment fee initially is charged to customers who make payments at authorized bill payment locations (e.g., large retail stores and drug stores) via check or cash, payment fees collected are reimbursed to the customer on their next bill. PECO began the process of reimbursing the fee for walk-in payments in recognition of supporting our most vulnerable communities. In 2023, for example, more than two hundred and fifty thousand (250,000) payments were made at authorized bill payment locations. Importantly, more than half – sixty four percent (64%) or ninety-four (94) out of one hundred forty-six (146) of the available authorized bill locations – are in the City of Philadelphia, where a majority of PECO's low-income customers are geographically located and most likely to utilize this payment option. Moreover, the fees associated with payments

made at authorized bill locations are absorbed by the Company at a cost of approximately five hundred thousand dollars ($500,000) annually.

The fees assessed for payments made outside of PECO's no-fee payment options are primarily associated with the processing of debit and credit card payments and are collected by the third-party processing vendor. As I am sure Mr. DeMarco is aware, credit card companies can charge significant fees for payments or purchases. The fees assessed to customers utilizing these methods are intended to offset the credit card fees assessed by the credit card industry. If PECO were to include these third-party processing vendor fees in its revenue requirement, this could potentially increase the revenue requirement by a minimum of five million dollars ($5,000,000) annually for residential payments, which is an amount that would be collected from all customers, including those currently using the no-fee payment option**.**

54. Q. Regarding Personal Identification Information ("PII"), Mr. DeMarco is waiting for discovery responses from the Company. Can you provide an update?

A. The discovery responses for OCA-21-12 and OCA-21-13 were served to the parties on June 16, 2024.

55. Q. What is your response to Mr. DeMarco's recommendation that PECO reduce the use and retention of PII and develop workflow and cybersecurity measures to reduce the threat of disclosure or theft of PII?

A. I would refer Mr. DeMarco to the discovery served to the parties in response to OCA OCA-21-12 and OCA-21-13. PECO follows industry best practices around

cybersecurity to safeguard and protect customer's PII. This includes, but is not limited to, multiple levels of access restrictions and encryption. However, due to the nature of PECO's business as a provider of retail electric and natural gas service, the retention of customer PII is vital to reduce the likelihood of fraudulent accounts being created and to provide needed creditworthiness information upon the creation of new accounts.

VIII. CONCLUSION

56. Q. Does this complete your rebuttal testimony at this time?

A. Yes, it does.

PECO Energy
2022 LIURP Evaluation
Final Report

April 2024

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Executive Summary

This report presents the findings from the Evaluation of PECO's 2022 Low Income Usage Reduction Program (LIURP). LIURP provides energy efficiency services and energy education to PECO's low-income customers to help them reduce their energy usage and increase the affordability of their energy bills. The Program addresses both electric and gas energy usage. This report describes the LIURP services and analyzes the impact of the Program on customers' energy usage, energy bills, and payments.

Evaluation

The goals of the evaluation were to analyze the LIURP services provided and the impacts of the services on participating customers. The following activities were undertaken.

- *Process Evaluation:* We requested program information from the PECO LIURP Manager, interviewed the CMC Program Manager, and reviewed and analyzed the quality control inspection findings.

- *Program Database Analysis:* We analyzed the 2022 LIURP services, homes, and customer characteristics.

- *Program Impacts Analysis:* We analyzed LIURP's impact on energy usage, energy costs, and bill payment.

PECO's LIURP

The Low Income Usage Reduction Program provides education, conservation, and weatherization measures to reduce electric and gas usage. Customers must meet the following usage and income eligibility criteria for participation.

- Household usage levels at or above 600 kWh per month for electric baseload, 1,400 kWh average seasonal heating usage for electric heat, or 50 ccf average seasonal heating usage for gas heat.

- Residential customers with household income at or below 200 percent of the federal poverty level (FPL).

CAP customers are targeted for Program services, but participation in CAP is not currently required for LIURP services. CAP customers are required to participate in LIURP if they are identified as high users (monthly usage of at least 500 kWh).

The number of customers who receive LIURP services each year is largely determined by the annual Program budget established in the settlement agreement of PECO's electric restructuring case (PUC Docket Numbers R-00973953 and P-00971265). The annual budget

for 2022 was $5.6 million for electric and $2.25 million for gas. In 2022, 3,667 customers received LIURP services.[1]

PECO contracts with CMC Energy Services to administer LIURP. PECO provides CMC with a list of potentially eligible customers and their energy usage data. CMC recruits these households in descending order based on highest usage and largest arrearages. CMC also contacts households who are directly referred from external organizations, including social and government agencies, and has begun advertising to households using Facebook.

CMC conducts an energy audit to determine the behavioral changes and measures required for usage reduction. Following the audit, CMC technicians and CMC subcontractors schedule appointments to install measures. For one year after LIURP services have been provided, PECO and CMC monitor the customer's monthly energy usage. CMC mails monthly progress letters to customers to highlight any changes in monthly usage, as compared to the customer's individual goal.

Program Statistics

In 2022, 20,417 customers were evaluated for LIURP services. There were 11,883 cancelled jobs and 4,867 customers who were ineligible for the Program. The cancellations were primarily due to lack of response to contact attempts.[2] In total, 3,667 customers received LIURP services in 2022; 82 of these received only education services and no measures, as there were no LIURP opportunities in these homes.

Table ES-1 displays how LIURP funds were expended in 2022. In total, $7.84 million was spent. Approximately 78 percent was for weatherization measures, 15 percent for the audit and education, and eight percent for administration.

Table ES-1
2022 LIURP Expenditures
By Category

Category	Amount Spent	Percent of Funds
Weatherization Measures	$6,092,230	78%
Audit/Education	$1,158,322	15%
PECO Administration	$592,699	8%
TOTAL	**$7,843,251**	**100%**

Table ES-2 displays the distribution of 2022 LIURP jobs by job type, for both electric and gas accounts. The table shows that 74 percent of jobs were classified as baseload, meaning that measures primarily address electric baseload usage. Since baseload jobs have lower job costs, they represent only 29 percent of total costs. The average cost for measures on these jobs was

[1] Eighty-two customers did not receive measures through LIURP. These customers only received education.
[2] See Table III-3.

$496. Gas heating jobs represented 13 percent of jobs and 34 percent of costs, averaging $3,312 in measure costs per home. Electric heating jobs averaged $4,272 per home.

Table ES-2
2022 LIURP Service Delivery and Expenditures
By Job Type

Job Type	# of Jobs	% of Jobs	Total Cost	% of Costs	Average Job Cost
Baseload	2,715	74%	$1,346,978	29%	$496
Electric Heating	394	11%	$1,683,040	37%	$4,272
Gas Heating	476	13%	$1,576,594	34%	$3,312
No LIURP Measure Costs*	82	2%	$0	0%	$0
TOTAL	**3,667**	**100%**	**$4,606,612**	**100%**	**$1,256**

*There were 82 accounts that received education only.

Participant Characteristics

PECO's LIURP database allows for extensive analysis of home and participant characteristics. Some of the important findings from this analysis included the following.

- *Supplemental heating:* Overall, 36 percent of customers who were treated by LIURP used supplemental heat. Thirty-five percent of the customers who had baseload LIURP services used electric supplemental heat.

- *Health and safety:* Over 4,000 smoke detectors were provided in 1,994 homes. Carbon monoxide detectors were provided in 1,640 homes.

- *LED bulbs:* LEDs were provided to 87 percent of the homes serviced. On average, 11 bulbs were provided in the homes that received LEDs.

- *Refrigerator replacement:* Refrigerators were replaced in 239 homes.

- *Air conditioner replacement:* Air conditioners were replaced in 846 homes.

- *Aerators and showerheads:* A total of 776 aerators were provided in 523 homes, and 511 showerheads were provided in 443 homes.

- *Water heaters:* Electric water heater replacements were performed in 34 homes, and heat pump water heaters were installed in 18 homes. Gas water heater replacements were provided in 36 homes.

- *Air sealing:* Air sealing was completed in 263 homes. However, only 130 customers received a blower door test.

- *Insulation:* Insulation was provided in 154 homes.

- *Door Sweeping/Weatherstripping:* Door sweeping/weatherstripping was provided in 976 homes.

- *Heat system repair:* Heating system repair work was performed in 401 homes.

- *Heating system replacement:* Heat pumps were replaced in 122 homes, furnaces in 44 homes, and boilers in 38 homes.

Usage Impacts

Energy usage was analyzed for the year prior to the LIURP audit visit and the year after service delivery was completed. The analysis included as close to a full year of pre- and post-treatment data as possible. Data were available for approximately 81 to 90 percent of the jobs that received measure installation.

Energy usage data were weather-normalized in the pre- and the post-usage periods to ensure that changes in energy usage were due to changes in usage patterns, rather than changes in weather. We used a degree-day normalization process to conduct this analysis, as well as a comparison group comprised of later LIURP participants to control for other changes that were exogenous to the Program.

Table ES-3 summarizes the overall usage impact results.

- *Baseload jobs* had average annual savings of approximately 847 kWh, or 7.1 percent of pre-treatment usage. Our preferred savings estimate, which uses a comparison group and weights for data attrition, is 1,030 kWh, or 8.6 percent of pre-treatment usage.

- *Electric heat* jobs had average annual savings of approximately 2,192 kWh, or 10.5 percent of pre-treatment usage. Our preferred savings estimate, which uses a comparison group and weights for data attrition, is 2,439 kWh, or 11.7 percent of pre-treatment usage.

- *Gas heat* jobs had savings of 88 ccf, or 7.2 percent of pre-treatment usage. Our preferred savings estimate, which uses a comparison group and weights for data attrition, is 95 ccf, or 7.8 percent of pre-treatment usage.

Table ES-3
Average Annual Usage and Saving

	#	Total Savings				LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post						
Electric Baseload (kWh)									
Non-Normalized	2,456	11,616	10,680	937***	8.1%	854	7.3%	83	0.7%
Degree Day Normalized	2,456	11,991	11,144	847***	7.1%	764	6.4%	83	0.7%
Electric Heat (kWh)									
Non-Normalized	320	19,630	17,100	2,530***	12.9%	2,458	12.5%	72	0.4%
Degree Day Normalized	320	20,838	18,646	2,192***	10.5%	2120	10.2%	72	0.3%
Gas Heat (ccf)									
Non-Normalized	412	1,122	969	153***	13.7%	153	13.7%	0	0.0%
Degree Day Normalized	412	1,214	1,126	88***	7.2%	88	7.2%	0	0.0%

***Denotes significance at the 99 percent level.

We compared the usage impact results to historical savings results.[3]

- Electric Baseload Jobs: The 2022 jobs had savings that were lower than the 2000-2021 average savings. Savings were 7.1 percent in 2022 compared to the historical average of 7.8 percent.

- Electric Heating Jobs: The 2022 jobs had savings that were higher than the 2000-2021 average. Savings were 10.5 percent in 2022 compared to the historical average of 7.0 percent.

- Gas Heating Jobs: The 2022 jobs had savings that were consistent with the 2000-2021 average. Savings were 7.2 percent in 2022, the same as the historical average of 7.2 percent from 2000-2021.

Measure Savings

The analysis also estimated the impact of specific LIURP measures on kWh and ccf savings. Table ES-4 displays results from this analysis. Savings were computed by running a regression model that predicted savings based on the measures provided.

In 2022, customers who only received LEDs and no other measures had average savings of 803 kWh, about the same as such homes in 2021. Heating systems provided some of the

[3] Tables IV-3A, 3B, and 3C provide the historical comparison of energy savings by job type.

highest savings, with heat pumps estimated to save 2,318 kWh per home and gas furnaces and boilers estimated to save 74 and 79 ccf per home.

Table ES-4
Measure Savings Estimates

	Savings	Cost/Home	$/Unit Saved	Measure Life	$/Unit Saved Over Lifetime
Electric Baseload (kWh)					
LED Only[1]	803 (±303)	$316[2]	--	10	--
LED	8 (±6)	$0	$0.02	10	<$0.01
Refrigerator	756 (±230)	$1,171	$1.55	12	$0.17
Freezer	756 (±230)	$267	$0.35	12	$0.04
Air Conditioner	108 (±120)	$885	$8.20	13	$0.87
Gas Heat (ccf)					
Gas Furnace	74 (±36)	$5,663	$76.52	15	$7.37
Boiler	79 (±39)	$11,030	$139.62	15	$13.45
Electric Heat (kWh)					
LED	24 (±20)	$1,011	$42.13	10	$5.46
Air Conditioner	1,521 (±727)	$658	$0.43	13	$0.05
Water heater	665 (±804)	$628	$0.94	12	$0.11
Air sealing only	1,030 (±854)	$1,237	$1.20	15	$0.12
Air sealing and insulation	713 (±530)	$3,539	$4.96	15	$0.48
Heat Pump	2,318 (±495)	$6,085	$2.63	15	$0.25

[1]The average number of LEDs provided to these customers was 11.5.
[2]This is the cost for the audit and education of customers who only received LEDs. The cost for the LEDs is paid for by the Act 129 Program.

LIURP Cost Effectiveness

We also analyzed the cost-effectiveness of LIURP by job type. Table ES-5 estimates the cost per unit saved based on different assumptions about measure life. These costs should be compared to retail rates to evaluate the cost-effectiveness of the LIURP at different measure lives.

The most reasonable assumption for electric baseload reduction is a ten-year measure life. The current cost per kWh of electricity is approximately $0.17. This table shows that the electric baseload investments were cost-effective in 2022, given that the cost per unit saved was slightly lower than the retail rate.

The most reasonable assumption for gas heating is a 15-year measure life. The current cost per ccf of gas is approximately $0.99. The table shows that the gas measures were not cost-

effective in 2022, given that the cost per unit saved was $3.69. LIURP would need to increase the savings that were obtained from the gas measures that were installed to be cost-effective.

Table ES-5
Cost Per Unit Saved
By Measure Life Assumption

	#	Average Savings	Average Total Cost	Cost Per Unit Saved	5-Year Measure Life	10-Year Measure Life	15-Year Measure Life
Electric Baseload							
Electric (kWh)	2,456	847	$887	$1.05	$0.24	$0.14	$0.10
Gas (ccf)	160	26	$931	$35.80	$8.27	$4.64	$3.45
Electric Heat							
Electric (kWh)	320	2,192	$4,503	$2.05	$0.47	$0.27	$0.20
Gas Heat							
Electric (kWh)	395	693	$459	$0.66	$0.15	$0.09	$0.06
Gas (ccf)	412	88	$3,374	$38.34	$8.86	$4.97	$3.69

Bill and Payment Impacts

The evaluation also included an analysis of the charges and payments made by customers in the pre- and post-treatment periods. Table ES-6 summarizes the results of this analysis. Total charges decreased by an average of $113, and total payments and credits decreased by an average of $115 from the pre to post period. The total bill coverage rate did not change significantly.[4] Customers were paying an average of 102.8 percent of their bills prior to LIURP treatment and an average of 103.5 percent of their bills following LIURP treatment.

Table ES-6
Bills, Payments, and Coverage Rates
Pre- and Post-LIURP Treatment

	#	Pre	Post	Change	Percent Change
Electric Baseload					
Total Charges	1,540	$1,149	$1,034	-$115***	-10.0%
Total Credits		$1,148	$1,044	-$104***	-9.0%
Total Coverage Rate		102.3%	104.1%	1.8%	1.7%

[4] The total coverage rate is the total of all customer payments, customer assistance, and other credits divided by the bill.

	#	Pre	Post	Change	Percent Change
Electric Heat					
Total Charges	99	$1,851	$1,650	-$201***	-10.9%
Total Credits		$1,887	$1,577	-$310***	-16.4%
Total Coverage Rate		102.0%	95.7%	-6.3%*	-6.2%
Gas Heat					
Total Charges	134	$1,916	$1,906	-$10	-0.5%
Total Credits		$2,020	$1,966	-$55	-2.7%
Total Coverage Rate		108.2%	104.6%	-3.7%	-3.4%
Education Only					
Total Charges	41	$1,072	$892	-$181***	-16.8%
Total Credits		$1,124	$851	-$273***	-24.3%
Total Coverage Rate		108.0%	98.0%	-10.0%	-9.3%
All Job Types					
Total Charges	1,814	$1,242	$1,129	-$113***	-9.1%
Total Credits		$1,252	$1,137	-$115***	-9.2%
Total Coverage Rate		102.8%	103.5%	0.7%	0.6%

***Denotes significance at the 99 percent level. *Denotes significance at the 90 percent level.

Key Findings and Recommendations

PECO's LIURP delivered usage reduction services and energy education to over 3,500 customers in 2022, many of whom had vulnerable household members. The program performed significantly better than recent years in terms of energy savings from electric heating jobs and gas heating jobs. Savings from electric heating jobs averaged 10.5 percent, compared to recent years that had savings below six percent. Savings from gas heating jobs were 7.2 percent compared to recent years that were all below five percent and often below three percent. Savings from electric baseload jobs were in line with the 20-year historic average. When accounting for the comparison group change, both electric baseload and electric and gas heating net savings were even higher compared to recent years.

The average measure cost remained more than double the historic average and stable compared to the previous year, which reduced the cost-effectiveness of LIURP. The increase in job costs was likely driven by rising material and labor costs stemming from the inflationary environment in the post-COVID economy. These cost increases are expected to continue to impact the program in future years.

We have the following recommendations to improve energy savings and the cost-effectiveness of LIURP.

- *Outreach:* While CMC was successful in increasing the number of contacted customers to pre-COVID levels, most customers did not respond to contact attempts. The current

procedure is to make at least three phone calls and send a follow-up letter.[5] CMC should increase the number of calls to high-usage customers and pilot additional methods of outreach to targeted neighbors when they are in the field, such as leaving door hangers. PECO is continuing work with CMC to expand and improve LIURP outreach.

- *Targeting High Users:* The savings for electric baseload and gas heating jobs are significantly higher for customers with higher pre-program usage. CMC was successful in 2022 in reaching higher usage customers than in some of the other recent years. They should continue to target higher usage households and focus on deploying major measures to homes where they are likely to maximize impact.

- *Major Measure Installation*: Savings on jobs with more major measures are significantly higher. CMC was successful in increasing the rate of air sealing and insulation on electric heating jobs compared to recent years. They were also successful in installing heat pumps in a greater percentage of homes. These changes lead to historic savings for the electric heating jobs. However, electric and gas heating job still have low levels of air sealing and insulation. CMC should work to increase the rate of air sealing and insulation work on both electric and gas heating jobs.

- *Health and Safety Remediation:* The health and safety component of the LIURP program has been effective at allowing additional energy saving measures to be installed through health and safety work. PECO should consider expanding their health and safety program by providing additional remediation work (such as electrical upgrades) that would enable energy efficiency measures in older homes.

[5] This is PECO's minimum standard for the number of contact attempts.

I. Introduction

This report presents the findings from the 2022 PECO LIURP evaluation. PECO's LIURP provides energy efficiency services and energy education to low-income households to help them reduce their energy usage and increase the affordability of their energy bills. This report describes the Program services and analyzes the impact of the Program on customers' energy usage, energy bills, and payments.

A. Background

PECO Energy has implemented a set of Universal Services Programs to meet requirements set by Pennsylvania's electric and gas restructuring legislation and various Public Utility Commission orders and agreements. The Universal Service goals are as follows.

- To protect consumers' health and safety by helping low-income customers maintain affordable utility service.
- To provide affordable utility service by making available payment assistance to low-income customers.
- To help low-income customers conserve energy and reduce residential utility bills.
- To ensure utilities operate universal service and energy conservation programs in a cost-effective and efficient manner.

The Universal Services Programs include the following four initiatives.

- A CAP payment assistance program that is designed to make energy bills more affordable by furnishing payment subsidies.
- A LIURP program that is designed to make energy bills more affordable by helping to reduce usage.
- A CARES program that is designed to assist households in developing appropriate strategies for maintaining energy service.
- A MEAF hardship fund program that is designed to furnish emergency payments to households that cannot pay their energy bills.

B. Evaluation Objectives and Activities

The goals of the evaluation were to analyze the LIURP services provided and the impacts of the services on participating customers. Three key activities were undertaken as part of this evaluation.

- *Process Evaluation:* We requested program information from the PECO LIURP Manager, interviewed the CMC Program Manager, and reviewed and analyzed the quality control inspection findings.

- *Program Database Analysis:* We analyzed the 2022 LIURP services, homes, and customer characteristics.

- *Program Impacts Analysis:* We analyzed LIURP's impact on energy usage, energy costs, and bill payment.

C. Organization of the Report

Five sections follow this introduction.

- Section II – Low Income Usage Reduction Program: This section describes PECO's LIURP design and implementation.

- Section III – Program and Participant Statistics: This section provides descriptive statistics on LIURP services delivered in 2022 and the customers who received these services.

- Section IV – Usage Impacts: This section analyzes the impacts of LIURP on customers' electric and gas usage.

- Section V – Payment Impacts: This section analyzes changes in customers' bills, payments, and arrearages after receiving Program services.

- Section VI – Summary of Findings and Recommendations: This section provides a summary of the key findings and furnishes recommendations for PECO's LIURP based on the analyses in this report.

APPRISE prepared this report under contract to PECO. PECO facilitated this research by furnishing Program data to APPRISE. Any errors or omissions in this report are the responsibility of APPRISE. Further, the statements, findings, conclusions, and recommendations are solely those of analysts from APPRISE and do not necessarily reflect the views of PECO.

II. Low Income Usage Reduction Program

PECO has implemented a set of Universal Service Programs to comply with Public Utility Commission Regulations. The Programs are designed for low-income, residential customers. One of these Programs is the Low-Income Usage Reduction Program (LIURP).

The Pennsylvania Public Utility Commission (PUC) requires that all electric and gas utilities in the state offer a Low-Income Usage Reduction Program to their customers. PECO has contracted with CMC Energy Services (CMC) to administer LIURP since the implementation of the Program in 1991. PECO and CMC worked together to create Program procedures that complied with Chapter 58 guidelines and continue to work together to design and implement Program changes when necessary. CMC works with subcontractors to install major Program measures and deliver energy efficient refrigerators.

The total 2022 LIURP budget was $7.85 million with $5.6 million for electric usage reduction and $2.25 million for gas usage reduction.

A. Program Management and Administration

CMC's Director of Operations is responsible for oversight of the LIURP Program, final contract requirements, and tracking key performance indicators (KPIs). CMC Program Managers and Associate Program Managers oversee the daily operations and report to the Director of Operations. The Program Managers and Associate Program Managers are also responsible for client management. They interact frequently with their equivalents at PECO to ensure smooth operations.

CMC also has staff within several of their other business units, listed below, that contribute to PECO's LIURP.

- Customer Care
- Marketing
- Information Technology
- Finance
- Subcontractor Management

CMC also has a field team, an inspection team, and a program support team, that support LIURP. The Field Supervisor is responsible for reviewing work orders and coordinating the field team, made up of three levels of technicians. Technicians at Level 1 are still in training, and Level 2 technicians perform baseload visits only. Level 3 Technicians perform electric and gas heating jobs and those involving combustion testing, although they can also do baseload jobs as needed.

The inspection team is led by a Quality Control (QC) Supervisor who overlaps with other programs such as Act 129. The QC Supervisor is responsible for managing Quality Control,

reporting data, summarizing findings, and managing CMC's relationship with PSD, the third-party inspector.

The program support team consists of a manager and two analysts. They process all information and prepare it for the Program Manager's review. Throughout this process, they perform validation checks to look for possible data errors, identify missing data, and make sure subcontractors have submitted the necessary paperwork and documentation for each project.

Customer care staff conduct inbound and outbound calling with customers and schedule appointments. Within this business unit there are also levels of expertise. The team is cross-program, meaning they perform calling for various utilities and programs unaffiliated with PECO.

CMC auditors, who are a part of the field team, collect data in the home, install smoke detectors and water-saving devices as needed, install Act 129 measures, educate the customer, and generate work orders for other measures. Subcontractors usually perform heating service, insulation, weatherization, and other major measures, but there is also an internal HVAC technician who completes jobs which are urgent or need a quick turnaround.

Subcontractors complete the services and replacement of heating systems and water heating systems. They perform weatherization, air sealing, and insulation. They also replace refrigerators and air conditioning units and recycle the old ones. Subcontractors also perform electrical work such as service upgrades, baseboard thermostats, and health and safety measures. Health and safety measures were piloted in 2019 and became permanent in 2020. They play an important role in LIURP because they often provide a bridge to the installation of other LIURP measures.

CMC provides oversight and support to the subcontractors. When there is a customer who is not satisfied with the scope of work, CMC will speak with the customer and visit the job site if needed.

Subcontractors can call CMC program support, they can interact with CMC through a portal, by email, or using Microsoft Teams. The portal allows subcontractors to upload documentation, provide notes about a job, or apply for a change to the work order. CMC receives questions and feedback from subcontractors daily. Each week, there is a scheduled meeting between each subcontractor and the QC Supervisor.

B. LIURP Eligibility and Benefits

PECO customers must meet the following criteria to participate in the Program.

- Residential customer who is not planning to move in the next 12 months.
- Income at or below 200 percent of the Federal Poverty Level (FPL).[6]
- Usage requirements
  - At least 500 kWh average monthly usage for CAP customers.
  - At least 600 kWh average monthly usage for baseload customers.
  - At least 1,400 kWh average seasonal heating usage for electric heating customers.
  - At least 50 ccf average seasonal heating usage for gas heating customers.

LIURP provides weatherization and conservation measures to promote usage reduction. Energy education tailored to the individual household's energy use is also provided to facilitate usage reduction.

The following measures may be provided.

- Insulation
- Air sealing
- Heating system repair or replacement
- Air conditioner replacement
- Refrigerator replacement
- Freezer replacement
- Water heater and pipe wraps
- Line voltage thermostats
- Faucet aerators
- Showerheads
- Smoke detectors
- Carbon monoxide detectors
- LED bulbs (All lighting installations are paid for as part of Act 129 funding.)

PECO and the PUC have pre-approved all LIURP measures. They have placed no cap on the amount of money spent per home. Smoke detectors and LEDs are much more commonly provided than some of the more costly measures.

[6] Since 1998, LIURP regulations have permitted companies to spend up to 20 percent of their annual Program budgets on customers with income between 150 and 200 percent of the FPL.

C. Qualification of Leads

PECO sends a quarterly download of high usage, low-income customers to CMC. Customers are also referred to LIURP through the following mechanisms.

- PECO Universal Services staff
- CAP call center
- Community Based Organizations (CBOs)
- Government agencies
- Prior Program recipients
- Universal Services Cares Unit
- CMC social media outreach via Facebook
- CMC email campaigns

The electronic file downloaded from PECO contains high energy users who are also LIHEAP recipients, Customer Assistance Program (CAP) participants, payment-troubled customers, or customers with multiple payment agreements. CMC reviews the lists and eliminates customers who have received LIURP within the past two years, refused Program services, or moved within the past 12 months. Typically, after these removals, the remaining customers on the downloaded file are eligible for and receive services from LIURP.

CMC screens all referrals from other sources to determine Program eligibility. If the household income and usage history are available and the customer is determined to be eligible, CMC enrolls the customer immediately. If income eligibility cannot be determined from PECO's system, CMC collects income data from the customer during the telephone intake. Typically, 25 to 30 percent of customers referred through other sources are determined to be eligible for and receive services from LIURP.

Referred customers may not receive LIURP services because of one of the following reasons.

- Refusal of LIURP services
- Insufficient usage history[7]
- Inactive account
- Income over the eligibility limit
- Non-responsive to CMC contacts
- Recently moved or is planning to move within one year
- Deceased
- Usage below the required level[8]
- Tenant with a landlord who will not provide consent

CMC is required to obtain consent from the landlord to provide services to a tenant. A landlord may not provide approval if they want to choose Program measures, are evicting the tenant,

[7] This may be the case if the customer recently moved into the home.
[8] There are some hardship cases where PECO makes exceptions to the usage requirement.

or are concerned about potential housing code violations.[9] Some landlords never respond to CMC inquiries. CMC is typically able to obtain landlord consent for more than 50 percent of renters.

Approximately 90 percent of customers who receive LIURP services are identified through the downloaded list, and about ten percent through other referrals.

D. Customer Outreach

PECO has undertaken new marketing efforts to increase uptake of LIURP services, including the following.

- LIURP Website: PECO is updating the LIURP website to have a more contemporary look, be more user-friendly, and be more educational. This change is expected to go live in April 2024.
- Events: PECO is working with their outreach department to provide information on LIURP at large events.
- Email Campaigns: PECO is including information on LIURP in their winter outreach, including new video advertisements. Additionally, they have developed a series of four emails that are sent to the list of high usage customers targeted for LIURP over the course of a month.

CMC's customer service representatives contact potential Program participants by telephone to explain Program services, obtain customer information, and confirm or determine eligibility.

If the customer is eligible, an appointment is scheduled for the energy audit. CMC will attempt to make this contact three times by telephone followed by a minimum of one time by mail over a 90-day period.[10] Information collected during this contact includes the following.

- Name of person responsible for bill payment
- Age of each household member
- Income sources for each household member
- Income amounts for each household member
- Property status and, if applicable, landlord contact information
- Housing type
- Occupation
- Employment status, marital status, and level of education

CMC assigns technical resources to the customer service desk to answer technical questions and provide a resource for customer care representatives. CMC also provides regular training

[9] Landlords are not required to contribute to the cost of LIURP services.
[10] This is PECO's minimum standard for the number of contact attempts.

with some elements of building science, reinforced Program guidelines, and information on what to do in particular situations.

One of the most challenging responsibilities the customer care representatives have is convincing the customer to allow a stranger to enter their home. Hesitation increased during the COVID-19 pandemic, as customers had health and safety concerns about allowing people into their homes. However, these concerns are no longer widespread. CMC reports that their call center representatives do a good job of preparing the customer for what the appointment entails and ensuring that the auditor will have access to all areas of the home.

Since 2021, CMC has used a progressive dialer system to reach more customers. The dialer system continuously calls customers and leaves messages if the customers do not answer the phone. When a customer picks up, the system transfers the call to a customer care representative. These systems can make 10,000 to 20,000 outbound calls each week. While these systems can provide more efficient calling, they can be frustrating to customers when there is a delay before speaking to a representative. Therefore, this system may not result in better contact outcomes.

E. Job Types

There are two different LIURP job types: Baseload and Heating. Baseload jobs focus on a household's lighting and appliances. Heating jobs include weatherization, insulation, and heating system repair or replacement. Both heating and baseload issues in a household are addressed when necessary. Once consent is obtained from the property owner, a renter becomes eligible for the full suite of services offered by LIURP.

F. Service Delivery

CMC prioritizes CAP participants for LIURP service delivery. All CAP participants with monthly usage at or above 500 kWh are considered for LIURP. Those with the lowest income and the greatest CAP benefits or active safety-related concerns receive the highest priority. CMC prioritizes remaining LIURP participants by energy use and income.

The first step in direct service delivery is the Program audit, performed by CMC staff. The auditor verifies the previously reported household characteristics, including income, number of household occupants, age of home, and years of occupancy. They also calculate the average household energy use per day, the energy use for each household appliance, temperature settings, and water temperature. Based on this information, the auditor may wrap the water heater and pipes, and install aerators, smoke detectors, showerheads, and LEDs during this initial audit visit.

CMC provided training to their audit staff to increase the thoroughness of directions given to subcontractors and to provide more documentation for each appointment. CMC requires the auditors to provide additional notes, documentation, and photos (if the customer agrees). Since auditors started using tablets in the field, it has become easier to take photos and attach them to the work orders. This provides subcontractors with better information to address each home.

In 2020, Virtual Energy Assessments were introduced. Virtual audits are still provided as an option for customers who are uncomfortable with the normal auditing process. Prior evaluations indicated that virtual audits were substantially less effective and are no longer actively marketed to customers.

If an audit requires follow up, CMC schedules the appropriate subcontractors to complete any necessary major measures, such as insulation, heating system repair or replacement, or new appliances. A work order is sent to the subcontractor to communicate the work that is needed. CMC aims for the subcontractor to install the measures within 30 days of work being issued to them and complete a final inspection within 60 days of the initial audit. Some jobs have health and safety concerns which can require additional work. This can lead to a delay as more subcontractors need to complete work and, in general, multiple subcontractors do not work on the same job simultaneously. Once the work has been completed and the home inspection is passed, the job is immediately considered complete.

CMC has instituted a process where subcontractors can talk to a QC supervisor in a timely fashion about any questions they have on the work orders. Additionally, every work order is vetted at the supervisor level to look for missing information and needed documentation or photos. CMC makes sure that the auditor provides notes to help the subcontractor.

CMC developed requirements for the timing of subcontractor appointments and invoicing. CMC recommends that subcontractors contact customers with work orders on the day that the work orders are received. This has been successful with the subcontractors that are able to do so. When the customer is contacted within days of their audit, the work is fresh in the customer's mind, and they are excited to have it done. This makes it more likely that the subcontractor will get back into the home, they are likely to have greater success in scheduling appointments, and they notice higher customer satisfaction levels.

G. Energy Education

PECO and CMC designed the energy education portion of LIURP to facilitate customers' clear understanding of the reasons for high energy use and to communicate how their behaviors contribute to their energy use and bills. The auditor provides the primary LIURP energy education session during the initial audit visit. CMC reports that this session lasts at least 30 minutes.[11] Further education is often provided by subcontractors when measures are installed and by other CMC QC inspectors during quality control inspections and follow-up telephone calls.

During the initial education session, the auditor reviews the customer's audit results and identifies ways that the customer can modify the behaviors of household members to save energy and money. The auditor and the customer set a monthly usage and bill reduction goal for the household. The auditor also provides the customer with an education package, which includes the following materials.

[11] Previous observations of CMC audits found that the education sessions were often much shorter than 30 minutes.

- Tips for saving energy
- 'Dangers of Using a Space Heater' pamphlet
- A brochure outlining the energy-saving benefits of LEDs and responsible lighting practices
- A brochure describing how to properly care for heating and cooling systems and preparing the home for energy savings during cold and hot weather months
- A brochure describing how to properly care the hot water system, how to reduce hot water consumption, and tips for how to use appliances efficiently
- PECO Energy Saving Tips calendar
- Referrals to CAP rate and other programs that the customer may be eligible for by county
- A PECO-branded folder informing customers of the benefits of participating in LIURP
- A brochure explaining the benefits of PECO's new Customer Assistance Program – Percentage of Income Payment Plan and other financial assistance programs available from PECO

The auditor reviews these educational materials with the customer and compares the household's energy cost estimate to the household's actual energy bill. Additionally, the auditor refers the customer to programs and agencies that might help them meet household needs and answers any questions the customer may have about the Program or the education session. The auditor reviews the measures that have been installed and those that will be installed by subcontractors. In addition, the auditor reviews the LIURP follow-up procedures that the customer can expect.

For one year after LIURP services have been provided, PECO and CMC monitor the customer's monthly energy usage. CMC mails monthly progress letters to customers to highlight any changes in monthly usage, as compared to the customer's individual goal. Each quarter CMC revises the letters to emphasize season-specific energy saving tips.

H. Quality Control

Three methods are primarily used for LIURP quality control.

- An annual evaluation, conducted by an independent program evaluator.
- Customer satisfaction surveys administered by CMC.
- Inspections by the CMC QC Inspector and a third-party inspector.

Third-Party Inspections and Observations

Performance System Development (PSD) has been conducting quality control for PECO's LIURP since April 2019. In response to a request for all assessments performed in the past year, PSD furnished 140 LIURP inspection reports from January through December 2023 (the impact evaluation focuses on 2022 to have a full year of post-treatment data available, but the QC review focuses on the most recent year available). These reports included seven inspection areas covered by the PSD inspector, each considered an "item" for the sake of analysis.

Table II-1 provides a summary of PSD's findings. In total, 140 jobs, or four percent of the jobs completed in 2023 were inspected. While 85 percent passed, 16 percent were passed with comments, and two percent with positive feedback. Fourteen percent of the inspections failed.

Table II-1
Inspection Summary

Inspections		
Assessment	**Number**	**Percent**
Passed	94	67%
Passed with Positive Comments	3	2%
Passed with Comments	23	16%
Not Passed (Fail)	20	14%
Total	**140**	**100%**

Table II-2 provides a detailed breakdown of the items missed during the inspections. The table shows that the most common issue was a missed opportunity for a measure or improvement, followed by an invoicing issue.

Table II-2
Inspection Findings

Item	# of Inspections	% of Inspections
Missed Opportunity	19	14%
Invoicing Issue	11	8%
Customer Altered Measure	10	7%
Contractor Call Requested	7	5%
Measure Not Addressed Correctly	4	3%
Inaccurate or Failed Testing	3	2%
Active Gas Leak	2	1%
No Items Missed	95	68%

Table II-3 provides a summary of the number of issues noted during the inspections On average, 0.4 items were missed, and 6.5 items were passed. Ninety-four percent of inspection items were passed.

Table II-3
Inspection and Survey Findings

Statistic	Inspections
Number of Audits	140
Mean # Items Passed	6.5
Mean # Items Missed	0.4
% of Items Passed	94%

Table II-4 shows the distribution of the number of items which were missed in the inspections. Most of the inspections, 94 percent, had no more than one item missed.

Table II-4
Distribution of Missed Items

Number of Missed Items	Inspections
Customers	140
0	68%
1	26%
2	2%
3	3%
4	1%
Total	**100%**

CMC Quality Control

CMC tries to obtain customer satisfaction surveys from at least ten percent of participants. The survey addresses technicians' courtesy and ability to answer customers' questions. Survey responses are combined into an overall score for each respondent.

CMC has historically asked customers to complete the technician feedback survey over the phone but is now offering a digital survey option that can be accessed via a QR code on the customer action form. However, to keep the technician feedback survey as accessible as possible, CMC also retained the phone option. CMC provides a phone number to clients at the time of the audit, and participants can choose to call with their feedback.

CMC inspects a minimum of five percent of baseload jobs and tries to inspect all heating jobs. However, they are not able to reach the heating inspection goal because customers stop answering calls after the work is completed. CMC surpasses the five percent goal for baseload inspections. A minimum of three attempts are made to schedule an inspection with heating customers and auto-generated letters are sent to customers to encourage them to make an appointment. CMC tries to communicate to customers that this inspection is an important part

of the process. PECO has worked with CMC to try to reduce the lag time between job completion and the inspection to increase customer acceptance of the inspection visit.

The inspector works from an inspection checklist and has the customer satisfaction survey, the home's audit results, and the completed work order to assist in the inspection. The inspector also conducts blower door, heating equipment, and carbon monoxide testing, and confirms the presence of all invoiced measures. In addition to post-completion inspections, the inspector sometimes accompanies CMC staff on audits and subcontractor staff on installations. CMC has access to the subcontractors' schedules, so if the inspectors have cancelled appointments, they observe the work of a subcontractor.

If a problem can be fixed immediately by an inspector, they will correct the issue at the time of the inspection. If there were issues such as failure to clean up or behavior that upset a customer, these will be raised with the subcontractor in feedback, but would not require them to return to the home. Where a measure was incorrectly installed or there was other work that needed to be done, an "action required" notice will be issued, and the subcontractor will be required to return to the home. Only a marginal percentage of jobs require a CMC installer to return to the home.

PECO Quality Control

The PECO LIURP manager validates LIURP invoices. They plan to select random homes for site visits to further assess the invoices in the future.

PECO has worked with CMC to improve customer satisfaction. CMC started to trend their customer service problems by attaching codes to every call. For example, a call may be coded as a work order inquiry. CMC has codes for every type of call that comes in, such as an air conditioner service or a refrigerator service. They can report on the number of each type of problem and see if it is increasing or decreasing. CMC tracks the issues that arise and works to root out the problems.

PECO has also worked with CMC to provide additional training to call center staff on handling customer disputes and dealing with difficult customers. CMC monitors call center representatives each month to assess the quality of their interactions.

PECO is now working with PSD to improve the QC scoring and develop a Program manual that provides weatherization and building code standards based on ANSI/BPI 1200 and current International Residential Codes. The manual will include the following topics.

- CST – Combustion Safety Testing
- BD – Blower Door diagnostics
- ZPD – Zone Pressure Diagnostic
- PP – Pressure Pan diagnostics
- Mechanical ventilation
- Health and Safety

I. Data and Reporting

LIURP databases contain the following information.

- Personal and household demographics
- Landlord contact information
- Audit results
- Quantity and costs of installed measures
- Referrals made to other programs
- Post treatment follow-up outreach results
- Completion dates and usage history
- Performance scorecard

CMC and PECO check the database for completeness and accuracy. This data is used to generate regular reports, including the following.

- Completed audits compared to projected audits
- Completed jobs compared to projected jobs
- Program costs by category
- Average cost per job
- Completed jobs by type
- Outreach call volume
- Customer demographics

CMC uses tablets in the field to improve the accuracy of data collection. There are checks programmed into the data entry fields, and there is also additional post-entry data validation that is conducted by CMC program support staff.

CMC and PECO monitor Program data monthly and the independent evaluator monitors Program data annually. In addition to this evaluation report, CMC and PECO produce an annual report to the PUC.

J. LIURP Training

PECO states in their contract with CMC that they require LIURP staff members to be adequately trained. CMC's QC Manager assesses the training needs of the CMC field and subcontractor staff. The CMC Office Manager assesses the training needs of the CMC administrative staff. CMC provides full training to each LIURP staff member at the time of hire, as well as ongoing training.

CMC provides bi-monthly training for their staff. Half of the training day is spent on in-depth training for a particular topic, while the other half is spent on team-building activities. Each week, there are also field meetings where information and feedback from the previous week is discussed with staff. Further, there are weekly hour-long meetings to reiterate any changes to the program guidelines, and internal monthly HR training.

During these meetings, key metrics and goals are reinforced. Important metrics include the number of measures per appointment, work orders generated, and errors with revisions needed to work orders. The most important goals are the number of appointments completed and percentage inspected (there is a 100 percent goal for heating inspections and a five percent goal for baseload inspections). For customer care staff, an important metric is whether enough appointments are generated to hit their participation goals.

Technicians also receive training to obtain Building Performance Institute (BPI) certification, and customer service representatives receive training in communications. Cross training and industry certification training is promoted as much as possible. Technicians also train in communications, and customer service staff receive some training in building performance, though not to the level of BPI certification. CMC also conducts an increasing number of heat pump trainings now that this technology is becoming an important part of LIURP.

CMC has a library of resources on customer service, building science, communications, and other subjects, which was developed during 2020 when field work was halted due to COVID.

CMC performs vetting of potential subcontractors and ensures that they have the proper certifications to perform the work. After the subcontractor is approved, CMC has an onboarding process to ensure that the subcontractor understands the process, inspections, work orders, line items, and invoicing.

Subcontractors are initially given a small number of work orders, often just one. For the first job, CMC will go out to the site with the subcontractor to evaluate them. The inspectors check that the subcontractor is badged and follows all rules and regulations when performing their work. If there are no issues, more work orders are issued, although the monitoring may continue to be more rigorous for a while until the subcontractor has demonstrated that they are reliable.

CMC has field demonstrations where one of the subcontractors will do a demonstration for CMC out in the field. Both auditors and subcontractors benefit from the demonstrations because it shows the subcontractors that their work is valuable, and it makes subcontractors feel more appreciated.

K. Program Coordination

CMC maintains a LIURP referral list consisting of other Universal Services Programs and state and county agencies that assist low-income customers. CMC staff make referrals during the initial energy audit, as well as during inspection and post-treatment follow-up calls. During the follow-up, CMC staff members ask customers whether they were able to obtain any benefits from the referrals they were given. Additionally, the CMC auditor provides CAP and LIHEAP applications to customers at the time of the LIURP audit.

L. Challenges

While COVID-related supply chain issues that CMC faced in 2020 and 2021 are no longer prevalent, jobs requiring major appliances, notably refrigerators, experienced large disruptions in 2021, leading to a backlog in 2022. In 2022, CMC was able to resolve most of this backlog by working with a new refrigerator vendor. However, limitations in funding prevented a complete resolution of this issue in 2022. CMC reports that the maximum delay for measure delivery is now about three months and they expect to resolve the full backlog in the second quarter of 2024.

A significant challenge that LIURP currently faces is the aging housing stock. Older homes often lack ductwork which limits options to replace baseboards. To overcome this challenge, CMC has done electric service upgrades and makes use of mini-splits in houses that lack ductwork. CMC has also used mini-splits to help address some backlog issues.

In 2023, customer cancellations were around 22 percent. This is a notable improvement from the 30 percent rate observed in 2021 and represents a return to the pre-COVID level of 25 percent. However, the return to normalcy also comes with more standard challenges. Home accessibility has been the main challenge faced by field staff, as children, pets, and other environmental factors can delay or prevent work from being done due to staff health and safety concerns.

Reaching high-usage low-income customers remains the biggest challenge faced in PECO's LIURP. CMC identified via a needs assessment that there were more low-income high-usage customers that could be reached through an expansion of the program. CMC is trying to focus outreach to untreated customers and minimize re-treating customers who have been serviced before.

III. Program and Participant Statistics

This section provides statistics on the LIURP services that were provided in 2022, as well as the characteristics of the homes and the customers who were served by the Program.

A. Participation

PECO screened 20,417 customers for LIURP services in 2022. Table III-1 shows that 11,883 cancelled, 4,867 customers were not eligible, and 3,667 received Program services.

Table III-1
Customers Evaluated for Program Services

Category	Number	Percent of Total
Cancelled	11,883	58%
Ineligible	4,867	24%
Treated	3,667	18%
TOTAL	**20,417**	**100%**

Table III-2 displays the reasons why customers were deemed ineligible for LIURP. While 45 percent were ineligible because they had previously been treated by LIURP, 23 percent had usage below the Program's guidelines, 17 percent had an insufficient usage history, and 14 percent were over the income limit. Customers treated in the past two years are not eligible for services.

Table III-2
Ineligible Customers

Category	Number	Percent of Total
Previously Treated in LIURP	2,214	45%
Usage Below Guidelines	1,105	23%
Insufficient Usage History	837	17%
Over Income	678	14%
Other	20	<1%
Conversion Error	7	<1%
Scope of Work Beyond Guidelines	5	<1%
TOTAL	**4,867**	**100%**

Table III-3 displays reasons why customers were cancelled. The largest group of customers, 77 percent, did not respond to contact attempts.

Table III-3
Cancelled Customers

Category	Number	Percent of Total
No Response To Contact Attempts	9,131	77%
Customer Refused	1,205	10%
Inactive Account	699	6%
Customer Moving	636	5%
Do Not Contact	57	<1%
Cancelled Needs To Rescheduled 60 Days Out	50	<1%
Cancelled Due To Health Concerns	38	<1%
Rescheduled By Program Request	34	<1%
Cancelled Due To Unsafe Environment	15	<1%
Cancelled At The Door Due To Inactive Account	7	<1%
Renovations In Progress	7	<1%
No Landlord Consent	2	<1%
Office Cancelled Miscellaneous Reasons	1	<1%
Other	1	<1%
TOTAL	**11,883**	**100%**

B. LIURP Services

This section describes LIURP services that were delivered in 2022. The total budget was $7.85 million, with $5.6 million for electric usage reduction and $2.25 million for gas usage reduction. Table III-4 shows the distribution of the spending. Seventy-eight percent was spent on weatherization measures and labor, 15 percent was spent on audits and education, and eight percent was spent on PECO administration.

Table III-4
2022 LIURP Expenditures
By Category

Category	Amount Spent	Percent of Funds
Weatherization Measures	$6,092,230	78%
Audit/Education	$1,158,322	15%
PECO Administration	$592,699	8%
TOTAL	**$7,843,251**	**100%**

Table III-5 displays the distribution of LIURP jobs and expenditures by job type. Jobs are classified as baseload, electric heating, or gas heating.[12] While 74 percent of the jobs were classified as baseload, they represented 29 percent of the total costs. The average cost for measures on these jobs was $496. Electric heating jobs represented 11 percent of jobs and 37 percent of costs, averaging $4,272 in measure costs per home. Gas heating jobs averaged $3,312 per home.

Table III-5
2022 LIURP Service Delivery and Expenditures
By Job Type

Job Type	# of Jobs	% of Jobs	Total Cost	% of Costs	Average Job Cost
Baseload	2,715	74%	$1,346,978	29%	$496
Electric Heating	394	11%	$1,683,040	37%	$4,272
Gas Heating	476	13%	$1,576,594	34%	$3,312
No LIURP Measure Costs*	82	2%	$0	0%	$0
TOTAL	**3,667**	**100%**	**$4,606,612**	**100%**	**$1,256**

*There were 82 accounts that received education only.

Table III-6 provides a more detailed breakdown of the type of work done in LIURP jobs, based on CMC's classification of measure types. Many jobs received more than one type of service. Ninety-seven percent of the customers received baseload services; but only seven percent received refrigerator replacement measures, which include refrigerator replacement, refrigerator removal, and freezer replacement. Seven percent received air sealing, six percent received weatherization, and four percent received insulation. Eight percent received a heating system tune-up, and 23 percent received an air conditioner replacement.

Table III-6
2022 LIURP Service Delivery and Expenditures

Work Type	# of Jobs	% of Jobs	Total Cost	% of Costs	Average Cost
Baseload*	3,546	97%	$213,827	5%	$72
Refrigerator Replacement**	241	7%	$271,768	6%	$1,137
Air Sealing	246	7%	$405,088	9%	$1,647
Weatherization	213	6%	$138,986	3%	$653
Insulation	148	4%	$243,580	5%	$1,646
Electrical	71	2%	$75,732	2%	$1,067
Heating System Tune Up	302	8%	$178,451	4%	$597
Heating System Replacement	276	8%	$1,666,260	36%	$6,037
Air Conditioner Replacement	846	23%	$842,881	18%	$1,002

[12] The job type classification shown in this table, and in this section of the report, comes from the LIURP database. In the Usage Impacts section of this report, some heating jobs were reclassified for more appropriate analysis.

Work Type	# of Jobs	% of Jobs	Total Cost	% of Costs	Average Cost
Water Heater Replacement	180	5%	$213,446	5%	$1,186
Water Heater Service	115	3%	$26,433	1%	$230
Health and Safety***	129	4%	$299,257	7%	$2,320
Direct Mail Weatherization Kit	18	<1%	$1,943	<1%	$108
TOTAL	**3,667**	**100%**	**$4,577,652**	**100%**	**-**

*2,961 of the 3,546 jobs with baseload measures had one or more baseload measures funded through LIURP. The other jobs had all baseload measures funded through Act 129. Average costs for the 6,154 baseload measures funded through LIURP are shown in this table.

**Measures that fall under the refrigerator replacement work type include refrigerator replacement, refrigerator removal, and freezer replacement. 239 of the 241 jobs with one of these measures had one or more of the measures funded through LIURP. The other jobs had all refrigerator replacement measures funded through Act 129. Average costs for the 242 refrigerator replacement measures funded through LIURP are shown in this table.

*** Health and Safety includes H&S appliance replacement, H&S basement waterproofing, H&S electric, H&S extermination, H&S heating system replacement, H&S miscellaneous repair, H&S site visit, H&S ventilation, H&S window replacement and H&S electric water heating system replacement, and H&S gas water heating system replacement.

Table III-7A provides information on the frequency of individual measures installed through LIURP. Some of the key pieces of information from this table are described below.

- *Health and safety:* Over 4,000 smoke detectors were provided in 1,994 homes. Carbon monoxide detectors were provided in 1,640 homes.
- *LED bulbs:* LEDs were provided in 87 percent of the homes serviced. On average, 11 bulbs were provided in the homes that received LEDs.
- *Refrigerator replacement:* Refrigerators were replaced in 239 homes.
- *Air conditioner replacement:* Air conditioners were replaced in 846 homes.
- *Aerators and showerheads:* A total of 776 aerators were provided in 523 homes, and 511 showerheads were provided in 443 homes.
- *Water heaters:* Electric water heater replacements were provided in 34 homes, and heat pump water heaters were installed in 18 homes. Gas water heater replacements were provided in 36 homes.
- *Air sealing:* Air sealing was completed in 263 homes. However, only 130 received a blower door test.
- *Insulation:* Insulation was provided in 154 homes.
- *Door Sweeping/Weatherstripping:* Door sweeping/weatherstripping was provided in 976 homes.
- *Direct Mail Weatherization Kit:* Direct mail weatherization kits were provided to 18 customers.

- *Heating system replacement:* Heat pumps were replaced in 122 homes, furnaces in 44 homes, and boilers in 38 homes.

Table III-7A
2022 LIURP Service Delivery and Expenditures
By Measure Type

Measure Category	Measure	Number of Jobs	% of Jobs	Total Number
Health and Safety	Carbon Monoxide Detectors	1,640	45%	1,794
	Smoke Detector	1,994	54%	4,271
	Smoke Detector Battery	234	6%	292
	H&S Appliance Replacement	8	<1%	22
	H&S Electrical	39	1%	39
	H&S Extermination	7	<1%	7
	H&S Heating System Replacement	2	<1%	2
	H&S Window Replacement	2	<1%	20
	H&S Electric Water Heating System Replacement	21	1%	21
	H&S Gas Water Heating System Replacement	42	1%	42
	Other Health and Safety*	37	1%	60
Electric Measure	LEDs	3,193	87%	36,295
	Refrigerator Replacement	239	7%	240
	Air Conditioner Replacement	846	23%	3,185
	AC Maintenance	6	<1%	6
	Power Strip	726	20%	1,341
	Freezer	4	<1%	4
Water Heating	Aerator	523	14%	776
	Showerhead	443	12%	511
	Water Heater Pipe Insulation	248	7%	248
	Water Heater Labor	158	4%	158
	Water Heater Part	145	4%	156
	Shower Valve	111	3%	132
	Electric Water Heater	34	1%	34
	Gas Water Heater	36	1%	36
	Heat Pump Water Heater	18	<1%	18

Measure Category	Measure	Number of Jobs	% of Jobs	Total Number
Insulation & Sealing	Air Sealing	263	7%	263
	Blower Door Test	130	4%	217
	Insulation	154	4%	154
	Weatherization	108	3%	108
	Duct/Pipe Insulation	78	2%	78
	Door Sweep/Weatherstripping	976	27%	2,033
	AC Sealing	122	3%	198
	Window Seal/Caulk	17	<1%	56
	Dryer Venting	39	1%	39
	Door/Lock	25	1%	35
	Direct Mail Weatherization Kit	18	<1%	1,570
Electrical	Electric Labor	57	2%	57
	Electric Part	54	1%	70
Thermostat	Line Voltage Thermostat	28	1%	98
	Manual Thermostat	2	<1%	2
	Programmable Thermostat	8	<1%	8
	Other Thermostat	65	2%	73
	SMART Thermostat	27	1%	28
Heating	Clean and Tune	119	3%	119
	Heating System Labor	401	11%	834
	Heating System Part	22	1%	25
	Electric Baseboard	15	<1%	26
	Gas Boiler	38	1%	38
	Furnace	44	1%	44
	Furnace Filter	50	1%	306
	Heat Pump	122	3%	122

* The measures that constitute this category are shown in Table III-7C

Table III-7B displays the measure installation rates by job type. The table shows that 30 percent of gas heat jobs and 31 percent of electric heat jobs received air sealing and that 13 percent of gas heat jobs and 23 percent of electric heat jobs received insulation.

Table III-7B
2022 LIURP Service Delivery
Measure Frequency by Job Type

Measure	All Participants			Analysis Group		
	Baseload	Electric Heat	Gas Heat	Baseload	Electric Heat	Gas Heat
Number of Customers	2,715	394	476	2,456	320	412
Carbon Monoxide Detector	51%	7%	50%	50%	8%	50%
Smoke Detector	54%	48%	68%	54%	47%	68%
Smoke Detector Battery	6%	4%	11%	7%	5%	10%
H&S Appliance Replacement	<1%	1%	<1%	<1%	1%	<1%
H&S Electrical	1%	4%	1%	1%	4%	1%
H&S Extermination	<1%	1%	<1%	<1%	0%	0%
H&S Heating System Replacement	<1%	0%	<1%	<1%	0%	<1%
H&S Window Replacement	0%	<1%	<1%	0%	<1%	0%
H&S Water Heating System Replacement	<1%	3%	<1%	<1%	3%	<1%
Other Health and Safety	<1%	5%	2%	<1%	5%	2%
LEDs	91%	83%	82%	91%	84%	83%
Refrigerator Replacement	6%	10%	9%	5%	9%	9%
Air Conditioner Replacement	25%	11%	25%	25%	10%	25%
AC Maintenance	0%	2%	0%	0%	2%	0%
Power Strip	20%	22%	20%	20%	22%	20%
Freezer	<1%	1%	0%	<1%	1%	0%
Aerator	7%	40%	37%	7%	39%	38%
Showerhead	8%	30%	25%	7%	28%	24%
Water Heater Pipe Insulation	3%	20%	21%	2%	20%	20%
Water Heater Labor	1%	9%	18%	1%	11%	17%
Water Heater Part	2%	14%	6%	2%	13%	6%
Shower Valve	2%	12%	4%	2%	10%	4%
Electric Water Heater	1%	4%	1%	1%	4%	<1%
Gas Water Heater	0%	1%	7%	0%	1%	6%
Heat Pump Water Heater	<1%	2%	<1%	<1%	1%	<1%
Air Sealing	<1%	31%	30%	<1%	31%	30%
Blower Door Test	0%	18%	13%	0%	18%	13%
Insulation	0%	23%	13%	0%	23%	14%
Weatherization	0%	12%	13%	0%	12%	13%
Duct/Pipe Insulation	0%	4%	13%	0%	4%	13%
Door Sweep/Weatherstripping	24%	40%	37%	23%	40%	37%

Measure	All Participants			Analysis Group		
	Baseload	Electric Heat	Gas Heat	Baseload	Electric Heat	Gas Heat
AC Sealing	2%	10%	8%	2%	10%	9%
Window Seal/Caulk	0%	3%	1%	0%	2%	1%
Dryer Venting	0%	2%	6%	0%	2%	6%
Door/Lock	0%	3%	3%	0%	4%	2%
Direct Mail Weatherization Kit	<1%	2%	<1%	<1%	1%	<1%
Electric Labor	<1%	11%	1%	<1%	11%	1%
Electric Part	<1%	11%	1%	<1%	11%	1%
Line Voltage Thermostat	<1%	6%	<1%	0%	7%	<1%
Manual Thermostat	0%	0%	<1%	0%	0%	<1%
Programmable Thermostat	<1%	1%	<1%	<1%	1%	<1%
Other Thermostat	0%	0%	14%	0%	0%	13%
SMART Thermostat	1%	0%	3%	1%	0%	2%
Clean and Tune	1%	<1%	18%	1%	<1%	19%
Heating System Labor	2%	32%	46%	2%	34%	44%
Heating System Part	<1%	1%	4%	<1%	1%	3%
Electric Baseboard	<1%	3%	<1%	0%	4%	<1%
Gas Boiler	<1%	0%	7%	<1%	0%	7%
Furnace	<1%	<1%	8%	<1%	<1%	8%
Furnace Filter	1%	1%	3%	1%	2%	3%
Heat Pump	0%	30%	<1%	0%	30%	<1%

Table III-7C shows that 60 jobs received health and safety measures. These included water heating, heating, and setback thermostats.

Table III-7C
Other Health and Safety Measures

Measure	Number of Jobs	% of Jobs	Total Number of Measures
Total Number of Measures	60		
H&S Materials	24	1%	24
H&S Labor	28	1%	29
Water Heating	2	<1%	2
Heating	5	<1%	5

Table III-7D displays the key measure installation rates for electric baseload jobs from 2012 through 2022. The table shows that the refrigerator replacement rate has declined since 2014. The average number of LEDs per job decreased from previous years to around 11 per home.

Table III-7D
2012-2022 LIURP Measure Frequency
Electric Baseload Jobs – All Customers

Measure	Electric Baseload – All Customers										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
# Customers	5,475	6,163	6,159	6,688	5,029	5,639	4,782	5,823	2,902	2,095	2,715
Refrigerator Removal	<1%	<1%	<1%	0%	<1%	<1%	0%	0%	<1%	0%	0%
Refrigerator Replacement	9%	15%	27%	26%	22%	21%	20%	10%	4%	12%	6%
LEDs	86%	85%	79%	71%	79%	93%	94%	92%	90%	94%	91%
Average # LEDs	7.0	4.7	6.6	4.4	6.3	10.5	11.9	12.5	14.0	14.4	11.3

Table III-7E displays electric baseload measures for the analysis group. This table shows the same general trends as the full sample.

Table III-7E
2012-2022 LIURP Measure Frequency
Electric Baseload Jobs – Analysis Group

Measure	Electric Baseload – Analysis Group										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
# Customers	3,982	4,781	4,798	4,971	3,876	4,787	3,800	4,773	1,263	1,460	2,456
Refrigerator Removal	<1%	<1%	<1%	0%	<1%	<1%	0%	0%	0%	0%	0%
Refrigerator Replacement	10%	16%	25%	16%	18%	18%	18%	7%	1%	11%	5%
LEDs	86%	84%	79%	73%	81%	94%	95%	93%	93%	94%	91%
Avg. # LEDs	7.1	4.6	6.6	4.6	6.2	10.7	12.1	12.4	16.6	13.1	11.3

Table III-7F displays the key measure installation rates for electric heating jobs from 2012 through 2022. The percent of electric heating jobs with a blower door test increased from only 5 percent in 2021 to 18 percent in 2022. Insulation rates also increased to 23 percent from 17 percent in 2018 to 2021. Heat pump installations increased from four percent in 2020 to 21 percent in 2021 and to 30 percent in 2022.

Table III-7F
2012-2022 LIURP Measure Frequency
Electric Heating Jobs – All Customers

Measure	Electric Heating – All Customers										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
# of Customers	494	743	981	777	710	782	695	628	404	563	394
LEDs	82%	71%	67%	64%	59%	81%	88%	91%	84%	82%	83%
Refrigerator Removal	0%	0%	0%	0%	<1%	0%	0%	0%	0%	0%	0%
Refrigerator Replacement	6%	11%	21%	22%	19%	20%	19%	16%	11%	17%	10%
Blower Door	32%	30%	27%	20%	30%	24%	18%	16%	11%	5%	18%
Air Sealing*	48%	42%	45%	45%	56%	45%	28%	26%	23%	27%	31%
Duct/Pipe Insulation	3%	4%	5%	2%	3%	2%	5%	3%	6%	2%	4%
Weatherization	24%	21%	21%	17%	26%	14%	10%	11%	10%	10%	12%
Insulation	37%	29%	31%	23%	32%	18%	17%	17%	17%	17%	23%
Line Voltage Thermostat	30%	29%	29%	33%	25%	16%	14%	21%	12%	22%	6%
Heating System Labor	10%	9%	12%	16%	19%	23%	17%	25%	31%	29%	32%
Heating System Part	2%	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%
Electric Baseboard	9%	10%	5%	5%	2%	1%	2%	4%	7%	7%	3%
Heat Pump	3%	4%	3%	3%	3%	4%	5%	5%	4%	21%	30%

*In 2018, the air sealing measure classification was updated to exclude certain non-air sealing measure descriptions. AC Sealing, Door Sweep/Weatherstripping, Window Seal/Caulk and Door/Lock were counted as air sealing in previous years but not in 2018. This explains the decline in air sealing measure frequency between 2017 and 2018.

Table III-7G shows similar trends for the electric heating analysis group.

Table III-7G
2012-2022 LIURP Measure Frequency
Electric Heating Jobs – Analysis Group

Measure	Electric Heating – Analysis Group										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
# of Customers	309	485	593	373	367	501	384	378	113	362	320
LEDs	84%	71%	64%	67%	54%	82%	89%	91%	83%	82%	84%
Refrigerator Removal	0%	0%	0%	0%	<1%	0%	0%	0%	0%	0%	0%
Refrigerator Replacement	7%	11%	19%	12%	16%	17%	16%	11%	3%	17%	9%
Blower Door	34%	30%	28%	10%	19%	16%	10%	9%	7%	5%	18%
Air Sealing*	49%	41%	44%	31%	41%	36%	16%	17%	18%	26%	31%
Duct/Pipe Insulation	4%	4%	6%	1%	1%	1%	3%	2%	6%	2%	4%

Measure	Electric Heating – Analysis Group										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Weatherization	22%	19%	21%	8%	16%	7%	6%	6%	10%	9%	12%
Insulation	37%	27%	32%	9%	23%	14%	10%	10%	13%	15%	23%
Line Voltage Thermostat	28%	27%	25%	24%	22%	15%	13%	20%	4%	23%	7%
Heating System Labor	12%	8%	11%	10%	13%	18%	10%	21%	17%	32%	34%
Heating System Part	2%	1%	2%	0%	0%	<1%	0%	<1%	0%	1%	1%
Electric Baseboard	8%	9%	4%	3%	2%	1%	1%	4%	4%	7%	4%
Heat Pump	4%	4%	3%	1%	1%	2%	3%	3%	2%	19%	30%

*In 2018, the air sealing measure classification was updated to exclude certain non-air sealing measure descriptions. AC Sealing, Door Sweep/Weatherstripping, Window Seal/Caulk and Door/Lock were counted as air sealing in previous years but not in 2018. This explains the decline in air sealing measure frequency between 2017 and 2018.

Table III-7H displays the key measure installation rates for gas heating jobs from 2012 through 2022. The percent of jobs receiving insulation and weatherization in 2022 was consistent with 2021 but lower than the historical average. Only seven percent of jobs received gas boilers in 2022, returning to the 2012-2020 average.

Table III-7H
2012-2022 LIURP Measure Frequency
Gas Heating Jobs – All Participants

Measure	Gas Heating – All Participants										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
# of Customers	1,282	1,623	1,222	1,303	1,624	1,188	1,359	1,347	254	389	476
Blower Door Test	60%	41%	40%	35%	35%	28%	20%	19%	17%	12%	13%
Air Sealing*	74%	57%	61%	64%	65%	51%	30%	35%	33%	30%	30%
Duct/Pipe Insulation	15%	13%	15%	12%	8%	5%	8%	8%	11%	8%	13%
Weatherization	41%	31%	32%	28%	29%	18%	11%	13%	14%	11%	13%
Insulation	46%	30%	35%	27%	26%	19%	14%	16%	21%	13%	13%
Heating System Labor	23%	17%	23%	28%	28%	23%	24%	34%	50%	47%	46%
Heating System Part	20%	13%	12%	8%	9%	8%	8%	7%	7%	5%	4%
Furnace	10%	4%	4%	5%	5%	5%	6%	4%	7%	5%	8%
Gas Boiler	7%	5%	4%	5%	7%	5%	6%	6%	9%	16%	7%

*In 2018, the air sealing measure classification was updated to exclude certain non-air sealing measure descriptions. AC Sealing, Door Sweep/Weatherstripping, Window Seal/Caulk and Door/Lock were counted as air sealing in previous years but not in 2018. This explains the decline in air sealing measure frequency between 2017 and 2018.

Table III-7I shows similar trends in installation rates for the gas heating analysis group.

Table III-7I
2012-2022 LIURP Measure Frequency
Gas Heating Jobs – Analysis Group

Measure	Gas Heating – Analysis Group										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
# of Customers	833	1,170	845	551	577	728	667	698	32	287	412
Blower Door Test	59%	38%	39%	25%	21%	20%	8%	13%	13%	10%	13%
Air Sealing*	74%	55%	58%	51%	50%	43%	13%	27%	19%	27%	30%
Duct/Pipe Insulation	15%	13%	12%	7%	4%	4%	3%	3%	9%	7%	13%
Weatherization	42%	30%	30%	15%	14%	13%	3%	8%	9%	9%	13%
Insulation	45%	30%	33%	15%	17%	16%	6%	11%	16%	10%	14%
Heating System Labor	22%	15%	17%	19%	18%	14%	13%	26%	31%	45%	44%
Heating System Part	21%	11%	7%	5%	5%	3%	3%	3%	9%	5%	3%
Furnace	10%	3%	3%	3%	2%	2%	2%	3%	9%	4%	8%
Gas Boiler	6%	4%	3%	2%	2%	2%	2%	4%	6%	17%	7%

*In 2018, the air sealing measure classification was updated to exclude certain non-air sealing measure descriptions. AC Sealing, Door Sweep/Weatherstripping, Window Seal/Caulk and Door/Lock were counted as air sealing in previous years but not in 2018. This explains the decline in air sealing measure frequency between 2017 and 2018.

Table III-7J displays the number of major measures installed in electric heating jobs from 2012 through 2022. Major electric measures include refrigerator replacement, freezer replacement, air conditioner replacement, water heater replacement, heat pumps, electric baseboards, insulation, and blower door guided air sealing. The percentage of electric heating jobs with no major measures was 43 percent in 2022, consistent with but much lower than the previous years.

Table III-7J
2012-2022 Number of Major Measures Installed
Electric Heating Jobs

# Maj. Meas.	Electric Heating Jobs										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Obs.	309	485	593	373	367	501	384	378	113	362	320
0	49%	51%	50%	73%	59%	64%	68%	66%	75%	47%	43%
1	17%	23%	21%	17%	21%	22%	20%	20%	13%	29%	28%
2	27%	18%	23%	8%	17%	10%	9%	11%	9%	17%	19%
3+	8%	8%	6%	1%	4%	4%	3%	3%	3%	7%	10%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Table III-7K displays the number of major measures installed in gas heating jobs from 2012 through 2022. Major gas measures include furnace replacement, water heater replacement, insulation, and blower door guided air sealing. As with electric heating jobs, the percent of gas heating jobs without a major measure in 2022 was consistent with 2021 but lower than other recent years.

Table III-7K
2012-2022 Number of Major Measures Installed
Gas Heating Jobs

# Maj. Meas.	Gas Heating Jobs										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Obs.	833	1,170	845	552	577	728	667	698	32	287	412
0	27%	49%	49%	67%	68%	73%	84%	78%	75%	63%	66%
1	29%	25%	23%	18%	17%	15%	10%	11%	9%	26%	21%
2+	44%	26%	28%	15%	15%	12%	6%	11%	16%	11%	13%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

C. Home Characteristics

CMC collects detailed information on customers who receive LIURP services, which allows for an in-depth analysis of the homes treated by the Program. We first examine the weather-normalized pre-treatment usage of customers who received LIURP treatments. Table III-8 shows that customers who received baseload services had an average electric usage of 11,991 kWh, electric heating customers had an average usage of 20,838 kWh, and gas heating customers had an average gas usage of 1,204 ccf.

Table III-8
Pre-Treatment Weather Normalized Usage

Job Type	**Number of Jobs**	**Jobs with Usage Data**	**Average Electric Usage (kWh)**	**Average Gas Usage (ccf)**
Baseload	2,715	2,456	11,991	741[1]
Electric Heating	394	320	20,838	0[2]
Gas Heating	476	412	10,049[3]	1,204
Total Excluding Those Without LIURP Measures	3,585	3,118	12,642[4]	1,074[5]
No LIURP Measures	82	60	10,961	764
Total Including Those Without LIURP Measures	**3,667**	**3,248**	**12,612**	**1,072**

[1]There are 160 baseload jobs with gas usage. [2]There are no electric heating jobs with gas usage. [3]There are 395 gas heating jobs with electric usage. [4]There are 58 education-only jobs with electric usage. [5]There are only four education-only jobs which have gas usage.

Table III-9 displays the primary heating source for LIURP jobs by job type and overall. Approximately 83 percent of all homes served had utility gas as their primary heating source.[13] Five percent used fuel oil and 11 percent had electric heat. Among baseload jobs a higher proportion had utility gas as their primary heating (91 percent) and far fewer had electric heat (one percent).

Table III-9
Primary Heating Source

Primary Heating Source	Baseload		Electric Heat		Gas Heat		All Jobs	
	# of Jobs	% of Jobs	# of Jobs	% of Jobs	# of Jobs	% of Jobs	# of Jobs	% of Jobs
Gas	2,539	91%	26	7%	469	98%	3,034	83%
Fuel Oil	195	7%	2	<1%	1	<1%	198	5%
Electric	35	1%	372	93%	8	2%	415	11%
Other	20	1%	0	0%	0	0%	20	1%
TOTAL	**2,789**	**100%**	**400**	**100%**	**478**	**100%**	**3,667**	**100%**

Table III-10 describes the use of supplemental heating by job type. Overall, 36 percent of the customers who were treated by LIURP used supplemental heat, nearly all of whom used electric supplemental heat. Thirty-five percent of the customers who had baseload services used electric supplemental heat.

Table III-10
Supplemental Heating

Supp. Heating Source	Baseload		Electric Heat		Gas Heat		All Jobs	
	# of Jobs	% of Jobs	# of Jobs	% of Jobs	# of Jobs	% of Jobs	# of Jobs	% of Jobs
None Used	1,789	64%	269	67%	298	62%	2,356	64%
Electric	982	35%	124	31%	176	37%	1,282	35%
Other	18	1%	7	2%	4	1%	29	1%
TOTAL	**2,789**	**100%**	**400**	**100%**	**478**	**100%**	**3,667**	**100%**

[13] Some jobs classified as Electric Heat had a rate type of Gas Heat and vice versa. These jobs were reclassified based on their rate type.

Table III-11 displays the type of air conditioning that LIURP recipients used. The most common type, with 66 percent, was a window unit. Eighteen percent had central air conditioning.

Table III-11
Air Conditioning

Air Conditioning	Number of Jobs	% of Jobs
Window Unit	2,437	66%
Central	668	18%
Wall Unit	183	5%
Central Heat Pump	131	4%
Portable Unit	99	3%
None Used	149	4%
TOTAL	**3,667**	**100%**

Table III-12 shows the home ownership characteristics of LIURP recipients. This table shows that 33 percent of the LIURP recipients were renters. Renters are not eligible for refrigerator replacement, air conditioner replacement, or furnace replacement.

Table III-12
Home Ownership

	Number of Jobs	% of Jobs
Own	2,463	67%
Rent	1,204	33%
TOTAL	**3,667**	**100%**

Homes treated by LIURP were fairly old. The average age of homes treated was 87 years, and 75 percent were more than 75 years old.

Table III-13
Home Age

	Number of Jobs	% of Jobs
≤ 25 Years	108	3%
26 – 50 Years	177	5%
51 – 75 Years	645	18%
76 Years or Older	2,737	75%
TOTAL	**3,667**	**100%**
Mean	87	

Table III-14A displays the dwelling type for the homes served under LIURP. The most common type was a row home, constituting 80 percent of homes served. Thirteen percent lived in other types of single-family homes, and four percent lived in multi-family homes.

Table III-14A
Dwelling Type

	Number of Jobs	% of Jobs
Row	2,939	80%
Other Single Family	489	13%
Multi	136	4%
Duplex	76	2%
Mobile	21	1%
Other	6	<1%
TOTAL	**3,667**	**100%**

Table III-14B displays the housing structure type for the homes served under LIURP. The most common type was wood with a full basement and an open joist attic.

Table III-14B
Type of Housing Structure

	Number of Jobs	% of Jobs
Wood, full basement, open joist attic	3,161	86%
Block, concrete or log, slab foundation, open joist attic	121	3%
Wood, full basement, knee wall attic	105	3%
Wood, crawl space, open joist attic	77	2%
Mobile home, post foundation	51	1%
Wood, slab foundation, open joist attic	21	1%
Wood, crawl space/basement, open joist attic	15	<1%
Other	116	3%
TOTAL	**3,667**	**100%**

Table III-15 describes the heated square footage of the homes treated by LIURP. Homes averaged 1,351 square feet. Fifty-four percent of the homes were more than 1,200 square feet.

Table III-15
Heated Square Footage

	Number of Jobs	% of Jobs
≤ 800	191	5%
801 - 1,000	408	11%
1,001 - 1,200	1,105	30%
1,201 or More	1,963	54%
TOTAL	**3,667**	**100%**
Mean	1,351	

D. Participant Characteristics

The Program also captures detailed information on the characteristics of participating households. Table III-16 shows that 79 percent of the households were female-headed, 45 percent contained at least one child, and 34 percent contained at least one elderly member.

Table III-16
Household Composition

	Number of Jobs*	% of Jobs
Female Household Head	2,876	79%
Male Household Head	766	21%
Child in Household (<18)	1,647	45%
Elderly in Household (>62)	1,240	34%

*Twenty-five customers were missing information about gender. Twelve customers were missing information about children and elderly in the household.

Table III-17 shows that the mean annual household income was $13,432. More than a third of households served had an annual income at or below $10,000. Only 19 percent had an annual income above $20,000.

Table III-17
Annual Income

	Number of Jobs	% of Jobs
≤ $5,000	615	17%
$5,001 - $10,000	751	21%
$10,001 - $15,000	1,016	28%
$15,001 - $20,000	565	16%
$20,001 or More	696	19%
TOTAL	**3,643**	**100%**
Mean	$13,423	

*Twenty-four customers were missing income information.

Table III-18 displays the household poverty level. Approximately 33 percent of the households had income below 50 percent of the Federal Poverty Level (FPL) and approximately four percent had income above 150 percent of the FPL.

Table III-18
Poverty Level

	Number of Jobs	% of Jobs
≤ 25%	646	18%
26% - 50%	542	15%
51% - 100%	1,668	46%
101% - 150%	621	17%
151% - 175%	109	3%
176% - 200%	50	1%
TOTAL	**3,636***	**100%**
Mean	67%	

*Thirty-one customers were missing income information.

Table III-19 describes the account type of households who participated in the Program. Approximately 76 percent were CAP participants and nine percent were Customer Choice participants.

Table III-19
Account Type

	Number of Jobs	% of Jobs
Jobs with Data	3,666	
CAP	2,787	76%
Customer Choice	318	9%

*One customer was missing data on CAP Enrollment and Customer Choice status.

Table III-20 displays the education level of the head of household. The majority of participants, 68 percent, had a high school education. Three percent had some high school, 17 percent had some college, and 11 percent had a college degree or higher.

Table III-20
Education Level

	Number of Jobs	% of Jobs
No Formal Education	10	<1%
Some Grade School	27	1%
Grade School	31	1%
Some High School	121	3%
High School	2,459	68%
Some College	602	17%
College Degree	285	8%
Some Graduate Work	5	<1%
Graduate Degree	102	3%
TOTAL	**3,642***	**100%**

*Twenty-five customers were missing education level information.

Table III-21 displays the primary income source for the LIURP participants. The table shows that the most common sources of income were work, public assistance, and pension or retirement. Thirty-four percent had full-time work as their primary source of income, 19 percent had public assistance, 14 percent had pension and/or retirement, ten percent had part-time work, and seven percent were dependent on another.

Table III-21
Income Source

	Number of Jobs	% of Jobs
Full Time	1,224	34%
Public Assistance	706	19%
Pension/Retirement	513	14%
Part-Time Work	353	10%
Dependent on Another	251	7%
Self-Employment	55	2%
Seasonal Employment	1	<1%
Other	540	15%
TOTAL	**3,643***	**100%**

*Twenty-four customers were missing income source information.

IV. Usage Impacts

This section of the report provides analysis of the impacts of LIURP on participants' annual electric and gas usage. The section describes the methodology for the analysis, the results for all participants by job type, and the results by type of service. We then provide estimates of the impacts of individual measures and the cost-effectiveness of LIURP.

A. Methodology

Customers who received LIURP services in 2022 were treated as the analysis group for this evaluation. We focus on the electric impacts for customers who were treated as electric baseload and electric heating jobs, and the gas impacts for customers who were treated as gas heating jobs, but we also analyze changes in the other fuel's usage.

Energy usage was analyzed for the year prior to the LIURP audit visit and the year after service delivery was completed. The analysis included as close to a full year of data pre- and post-treatment as possible. Table IV-1A displays the attrition statistics for the usage analysis. Customers were included in the analysis if their pre- and post-usage data each spanned between 270 and 390 days. Some additional customers were removed from the analysis if their usage was below 1,200 kWh or 300 ccf, or if their change in usage was greater than 65 percent. After these eliminations, we included 90 percent of the treated baseload households in the usage analysis, 81 percent of the treated electric heating households, and 87 percent of the treated gas heating households.

Table IV-1A
Usage Impact Data Attrition

	Electric Baseload	Electric Heating	Gas Heating	Education Only
Original Population*	2,715	394	476	82
Not Enough Pre-Treatment Days	20	13	8	1
Not Enough Post-Treatment Days	167	43	36	8
All Estimated Reads in Pre or Post	4	0	2	0
Pre-Usage Below 1200 kWh or 300 ccf	0	0	2	0
Post-Usage Below 1200 kWh or 300 ccf	2	0	2	0
Change in Total Usage>65%	55	3	7	3
Additional Outliers	11	15	7	10
Final Sample	2,456	320	412	60
% Included in Analysis	**90%**	**81%**	**87%**	**73%**

*As Program data did not furnish rate types (electric or gas), only the customers with usage data were included in the number of original populations for Education Only groups.

Table IV-1B displays the attrition for the comparison group of 2022 participants. Between 72 and 77 percent of these comparison group customers were included in the final analysis.

Table IV-1B
Comparison Group Data Attrition

	Electric Baseload	Electric Heating	Gas Heating
Original Population	3,813	416	371
Not Enough Pre-Treatment Days	463	64	57
Not Enough Post-Treatment Days	243	16	24
All Estimated Reads in Pre or Post	3	2	0
Pre-Usage Below 1200 kWh or 300 ccf	1	2	1
Post-Usage Below 1200 kWh or 300 ccf	0	0	0
Change in Total Usage>65%	149	24	3
Additional Outliers	25	9	6
Final Sample	2,929	299	280
% Included in Analysis	**77%**	**72%**	**75%**

Energy usage data were weather normalized in the pre- and the post-usage period to ensure that changes in energy usage were due to changes in usage patterns, rather than due to changes in weather. We used a degree-day normalization process to conduct this analysis. This process involved the following steps.

1. Calculate the heating and cooling degree-days that are included in each usage period.

2. Determine whether periods should be classified as baseload periods, heating periods, or cooling periods, based on the number of usage and heating and cooling degree-days in the period.

3. Calculate the total baseload period usage, heating period usage, and cooling period usage.

4. Calculate the relationship between heating usage minus baseload usage and degree- days. Use that slope and the average long-term heating degree-days to calculate normalized heating period usage.

5. Follow the same method to calculate normalized cooling period usage.

6. Add up the baseload usage, heating period usage, and cooling period usage to obtain the normalized annual usage.

For comparison, we also produced weather normalized results using PRISM analysis. We discuss differences between the degree day and PRISM results in the following section. The degree-day approach allowed for a higher percentage of cases to be included, due to fewer restrictions on data availability and the fact that cases did not need to be removed because the model did not run, or the model had a poor fit.

While the PUC does not require that baseload usage is normalized, we conducted the normalization process on the baseload usage as well as the heating and cooling usage. Baseload usage may vary with weather because of the use of air conditioning, the gas furnace's electric fan, the refrigerator, and use of electric space heaters.

B. Energy Savings Impacts

This section provides the average weather-normalized usage for the pre- and post-treatment periods and the average energy savings. Table IV-2A displays these results by job type.

The table shows the following degree-day normalized savings.

- Baseload jobs had average annual savings of approximately 847 kWh, or 7.1 percent of pre-treatment usage. Baseload jobs also had a 26 ccf decrease in gas usage, or 3.4 percent of pre-treatment usage.

- Electric heat jobs had average annual savings of approximately 2,192 kWh, or 10.5 percent of pre-treatment usage. (All electric heat jobs had low gas usage and were dropped from the analysis.)

- Gas heat jobs had savings of 88 ccf, or 7.2 percent of pre-treatment usage. Gas heat jobs also had electric savings of 693 kWh, or 6.9 percent of pre-treatment usage.

Table IV-2A
Average Annual Usage and Saving

	#	Total Savings				LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post						
Electric Baseload (kWh)									
Non-Normalized	2,456	11,616	10,680	937***	8.1%	854	7.3%	83	0.7%
Degree Day Normalized	2,456	11,991	11,144	847***	7.1%	764	6.4%	83	0.7%
Degree Day-PRISM cases	2,412	12,019	11,150	869***	7.2%	786	6.5%	83	0.7%
PRISM Normalized	2,412	11,922	11,120	802***	6.7%	719	6.0%	83	0.7%
Electric Heat (kWh)									
Non-Normalized	320	19,630	17,100	2,530***	12.9%	2,458	12.5%	72	0.4%
Degree Day Normalized	320	20,838	18,646	2,192***	10.5%	2120	10.2%	72	0.3%
PRISM Normalized	320	20,755	19,039	1,716***	8.3%	1644	7.9%	72	0.3%
Gas Heat (ccf)									
Non-Normalized	412	1,122	969	153***	13.7%	153	13.7%	0	0.0%
Degree Day Normalized	412	1,214	1,126	88***	7.2%	88	7.2%	0	0.0%
Degree Day-PRISM cases	409	1,216	1,127	89***	7.3%	89	7.3%	0	0.0%

	#	Total Savings				LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post						
PRISM Normalized	409	1,192	1,122	70***	5.9%	70	5.9%	0	0.0%
Gas Heat (kWh)									
Non-Normalized	395	9,726	9,152	574***	5.9%	484	5.0%	90	0.9%
Degree Day Normalized	395	10,049	9,355	693***	6.9%	603	6.0%	90	0.9%
Degree Day-PRISM cases	385	10,045	9,367	677***	6.7%	587	5.8%	90	0.9%
PRISM Normalized	385	9,859	9,385	474***	4.8%	384	3.9%	90	0.9%
Electric Baseload (ccf)									
Non-Normalized	160	687	636	50***	7.3%	50	7.3%	0	0.0%
Degree Day Normalized	160	748	722	26***	3.4%	26	3.5%	0	0.0%
Degree Day-PRISM cases	156	754	724	31***	4.1%	31	4.1%	0	0.0%
PRISM Normalized	156	750	731	19**	2.5%	19	2.5%	0	0.0%
Education Only (kWh)									
Non-Normalized	58	10,811	10,220	591***	5.5%	591	5.5%	0	0.0%
Degree Day Normalized	58	10,961	10,592	369*	3.4%	369	3.4%	0	0.0%
Degree Day-PRISM cases	56	11,051	10,732	319	2.9%	319	2.9%	0	0.0%
PRISM Normalized	56	10,870	10,668	202	1.9%	202	1.9%	0	0.0%
Education Only (ccf)									
Non-Normalized	4	707	635	73	10.3%	73	10.3%	0	0.0%
Degree Day Normalized	4	767	751	15	2.0%	15	2.0%	0	0.0%
PRISM Normalized	4	759	765	-6	-0.8%	-6	-0.8%	0	0.00%

Note: All Electric Heat (kWh), and Education Only (ccf) accounts survived PRISM attrition, thus the lack of a "Degree Day-PRISM cases" row. Additionally, usage for Electric Heat (ccf) accounts were not displayed in this table because all such accounts were dropped from the analysis for low usage.

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.

Table IV-2B uses the comparison group of later LIURP participants to control for the impact of other factors exogenous to LIURP that may have impacted usage. The comparison group adjustment increased savings slightly for electric baseload, electric heating, and gas heat main fuel impacts. The comparison group adjustment reduced savings for electric use of gas heating jobs and gas use of electric baseload jobs.

Table IV-2B
Average Annual Usage and Savings
With Comparison Group

	Treatment Group Savings					Comparison Group Savings					Net Savings	
	#	Usage		Annual Savings		#	Usage		Annual Savings			
		Pre	Post	kWh/ccf	%		Pre	Post	kWh/ccf	%	kWh/ccf	%
Elec BL (kWh)	2,456	11,991	11,144	847***	7.1%	2,929	11,412	11,595	-183***	-1.6%	1030***	8.6%
Elec Heat (kWh)	320	20,838	18,646	2,192***	10.5%	299	22,423	22,649	-227	-1.0%	2419***	11.6%
Gas Heat (ccf)	412	1,214	1,126	88***	7.2%	280	1,402	1,409	-7	-0.5%	95***	7.8%
Gas Heat (kWh)	395	10,049	9,355	693***	6.9%	262	9,659	9,496	163	1.7%	530***	5.3%
Elec BL (ccf)	160	748	722	26***	3.4%	233	760	737	24***	3.1%	2	0.2%

***Denotes significance at the 99 percent level.

Table IV-2C displays average heating and cooling degree days in the pre- and post-treatment usage periods for the 2022 LIURP participants, compared to the 20-year average that was used in the normalization process. The table shows that the post-treatment heating degree days were fifteen to eighteen percent lower than the pre-treatment heating degree days for all job types. The table also shows a decrease in the number of cooling degree days for all job types.

Table IV-2C
Average Heating and Cooling Degree Days
Relative to 20-year Average

Job Type	#	Pre-CDD	Post-CDD	CDD Difference		Pre-HDD	Post-HDD	HDD Difference	
				#	%			#	%
Electric Baseload	2,456	905	818	-87***	-10%	3,981	3,397	-584***	-15%
Electric Heat	320	897	814	-84***	-9%	3,939	3,391	-547***	-14%
Gas Heat	412	888	868	-20**	-2%	4,041	3,329	-712***	-18%
Education Only (kWh)	58	947	803	-145***	-15%	3,960	3,378	-582***	-15%
Education Only (ccf)	4	917	745	-172	-19%	3,940	3,226	-714	-18%
20-Year Average (2004-2023)		843				4,304			

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level.

Another important factor in estimating energy savings is the degree to which the final analysis group, with enough usage data to include in the results, is comparable to the full population of treated households. In 2022, the analysis group was similar to the overall treatment group in terms of the number of major measures installed. The following tables show that when adjusting for differences between the treatment group and the analysis group there is no substantial change in the net savings.

Table IV-2D shows that the analysis group is representative of the overall treatment group for electric baseload customers with major measures. Twenty-nine percent of all electric baseload jobs and the electric baseload analysis group received a major measure. Since the proportions between the analysis group and all customers are identical, the weighted savings of 847 kWh and 7.1 percent are also identical to the unweighted savings. We found that the weighted net savings estimate of 1,030 kWh, or 8.6 percent of pre-treatment usage, was also identical to the unweighted net savings. This is our best estimate of savings for the electric baseload jobs.

Table IV-2D
Electric Baseload Savings
By Level of Service

Savings Estimate	Measure Type	All Customers		Analysis Group		Savings		Unweighted Savings		Weighted Savings	
		#	%	#	%	kWh	%	kWh	%	kWh	%
Gross Savings	Basic	1,924	71%	1,742	71%	758***	6.4%	847	7.1%	847	7.1%
	Major	791	29%	714	29%	1,065***	8.8%				
Net Savings								1,030	8.6%	1,030	8.6%

***Denotes significance at the 99 percent level.

Table IV-2E shows that the analysis group is representative of the overall treatment group for electric heating customers with major measures. While 29 percent of all electric heating jobs had one major measure and 29 percent had two or more major measures, 28 percent of the electric heating analysis group had one major measure and 29 percent had two or more major measures. When accounting for this slight difference, the savings estimate increases from 2,192 kWh, or 10.5 percent, to 2,210 kWh, or 10.6 percent.

We adjusted the net savings by the same percentage to develop a comparison group adjusted, weighted savings estimate of 2,439 kWh, or 11.7 percent of pre-treatment usage. This is our best estimate of savings for the electric heating jobs.

Table IV-2E
Electric Heating Customers Savings
By Number of Major Measures

Savings Estimate	Number of Major Measures	All Customers		Analysis Group		Savings		Unweighted Savings		Weighted Savings	
		#	%	#	%	kWh	%	kWh	%	kWh	%
Gross Savings	0	163	42%	138	43%	1,258***	6.1%	2,192	10.5%	2,210	10.6%
	1	116	29%	89	28%	2,877***	13.8%				
	2 or More	115	29%	93	29%	2,922***	13.6%				
Net Savings								2,419	11.6%	2,439	11.7%

***Denotes significance at the 99 percent level.

Table IV-2F shows that the analysis group is representative of the overall treatment group for gas heating customers with major measures. While 21 percent of all gas heating jobs had one major measure and 12 percent had two or more major measures, 21 percent of the gas heating analysis group had one major measure and 13 percent had two or more major measures. Accounting for this change does not change the savings estimate of 88 ccf or 7.2 percent.

We adjusted the net savings by the same percentage to develop a comparison group adjusted, weighted savings estimate of 95 ccf or 7.8 percent of pre-treatment usage. This is our best estimate of savings for the gas heating jobs.

Table IV-2F
Gas Heating Customers Savings
By Number of Major Measures

Savings Estimate	Number of Major Measures	All Customers		Analysis Group		Savings		Unweighted Savings		Weighted Savings	
		#	%	#	%	ccf	%	ccf	%	ccf	%
Gross Savings	0	316	67%	273	66%	70***	5.7%	88	7.2%	88	7.2%
	1	101	21%	86	21%	103***	8.8%				
	2 or More	59	12%	53	13%	153***	13.3%				
Net Savings								95	7.8%	95	7.8%

***Denotes significance at the 99 percent level.

The rest of the report focuses on the degree day normalized savings. Tables IV-3A, 3B, and 3C provide the historical comparison of energy savings by job type.

Table IV-3A displays historical savings of electric baseload jobs. The table shows that the 2022 jobs had percentage savings that were lower than the 2000-2021 average savings. Savings were 7.1 percent in 2022 compared to the historical average of 7.8 percent (not accounting for the comparison group change). However, the average annual household savings of 847 kWh were higher than the historical average of 831 kWh and significantly higher than electric savings in recent years. The 2022 jobs had pre-treatment usage that was about 12 percent higher than the historical average and spending that was more than double the historical average (some due to inflation), both of which should lead to greater savings.

Table IV-3A
Time-Series Comparison of Annual Usage and Savings
Electric Baseload Jobs

	Pre-Use	Post-Use	Savings	Percent Savings	Measure Cost
2022	**11,991**	**11,144**	**847**	**7.1%**	**$487**
2000-2021 Average	**10,734**	**9,903**	**831**	**7.8%**	**$221**
2021	12,543	11,642	900	7.2%	$466
2020	11,394	11,190	203	1.8%	$295
2019	10,399	9,760	640	6.2%	$128
2018	10,010	9,336	674	6.7%	$223
2017	10,508	9,888	620	5.9%	$184
2016	10,557	9,885	673	6.4%	$213
2015	10,035	9,226	809	8.1%	$173
2014	9,969	9,120	849	8.5%	$161
2013	10,707	9,877	830	7.7%	$182
2012	11,461	10,911	550	4.8%	$161
2011	10,758	10,148	610	5.7%	$258
2010	11,370	10,147	1,223	10.8%	$201
2009	12,144	11,090	1,054	8.7%	$186
2008	10,990	10,276	714	6.5%	$191
2007	10,919	10,032	887	8.1%	$240
2006	10,695	9,953	742	6.9%	$214
2005	11,188	10,073	1,115	10.0%	$208
2004	9,309	8,384	925	9.9%	$215
2003	10,040	8,679	1,361	13.6%	$214
2002	10,591	9,687	904	8.5%	$192
2001	10,821	9,722	1,099	10.2%	$296
2000	9,741	8,843	898	9.2%	$268

Table IV-3B displays historical savings of electric heating jobs. The table shows that the 2022 jobs had savings that were higher than the 2000-2021 average. Savings were 10.5 percent in 2022 compared to the historical average of seven percent (not accounting for the comparison group change). The electric heating pre-treatment usage was higher than in the past, averaging 20,838 kWh, compared to the historical average of 20,182 kWh. Moreover, the cost of measures was more than double the historical average, however this is at least partly due to inflation.

Table IV-3B
Time-Series Comparison of Annual Usage and Savings
Electric Heating Jobs

	Pre-Use	Post-Use	Savings	Percent Savings	Measure Cost
2022	**20,838**	**18,646**	**2,192**	**10.5%**	**$4,057**
2000-2021 Average	**20,182**	**18,756**	**1,426**	**7.0%**	**$1,659**
2021	20,771	19,936	835	4.0%	$3,423
2020	21,319	20,477	842	4.0%	$1,809
2019	18,909	17,928	981	5.2%	$1,131
2018	16,041	15,064	977	6.1%	$772
2017	15,920	15,152	767	4.8%	$831
2016	17,180	16,182	998	5.8%	$991
2015	14,760	13,653	1,106	7.5%	$622
2014	16,263	15,150	1,113	6.8%	$1,301
2013	21,350	19,416	1,934	9.1%	$1,310
2012	20,700	19,465	1,235	6.0%	$1,430
2011	19,402	17,899	1,503	7.7%	$1,798
2010	19,662	18,534	1,128	5.7%	$2,094
2009	23,179	21,493	1,686	7.3%	$2,514
2008	20,786	18,614	2,172	10.4%	$2,332
2007	21,017	19,888	1,129	5.4%	$1,735
2006	21,890	20,458	1,433	6.5%	$1,643
2005	21,956	20,326	1,629	7.4%	$1,824
2004	23,449	21,148	2,301	9.8%	$1,782
2003	22,510	20,220	2,290	10.2%	$1,646
2002	22,745	21,441	1,304	5.7%	$1,753
2001	22,825	20,469	2,356	10.3%	$2,234
2000	21,368	19,724	1,644	7.7%	$1,521

Table IV-3C displays historical savings for gas heating jobs. The table shows that the 2022 gas heating jobs had savings that were in line with the 2000-2021 average. Savings were 7.2 percent in 2022, equal to the historical average of 7.2 percent (not accounting for the comparison group change). Pre-treatment usage in 2022 was about 10 percent higher than the historical average and spending in 2022 was slightly less than double the historical average, again partly due to inflation.

Table IV-3C
Time-Series Comparison of Annual Usage and Savings
Gas Heating Jobs

	Pre-Use	Post-Use	Savings	Percent Savings	Measure Cost
2022	**1,214**	**1,126**	**88**	**7.2%**	**$3,357**
2000-2021 Average	**1,093**	**1,011**	**82**	**7.2%**	**$1,732**
2021	1,195	1,172	23	1.9%	$3,864
2020	1,262	1,202	60	4.7%	$3,107
2019	1,025	975	51	4.9%	$1,233
2018	904	888	16	1.8%	$666
2017	968	944	24	2.5%	$912
2016	944	914	31	3.3%	$918
2015	977	946	31	3.2%	$934
2014	906	879	27	2.9%	$1,117
2013	1,022	945	77	7.5%	$1,086
2012	989	924	65	6.6%	$1,820
2011	1,025	959	67	6.5%	$2,410
2010	1,052	991	61	5.8%	$2,253
2009	1,090	998	92	8.4%	$2,100
2008	1,087	984	103	9.5%	$2,016
2007	1,054	965	89	8.4%	$1,914
2006	1,128	1,037	91	8.0%	$1,640
2005	1,206	1,039	168	13.9%	$1,643
2004	1,205	1,037	168	13.9%	$1,789
2003	1,227	1,086	141	11.5%	$1,422
2002	1,253	1,159	94	7.5%	$1,488
2001	1,262	1,097	165	13.1%	$2,003
2000	1,265	1,106	159	12.6%	$1,763

Table IV-4 displays the seasonal analysis of energy savings by job type. The table shows that jobs achieved savings from baseload, heating, and cooling usage across all job types, with the exception of education only.

Table IV-4
Seasonal Usage Analysis

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Share of Savings	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Baseload	2,456	7,338	6,886	452***	6.2%	53.4%	369	5.0%	83	1.1%
Heating		2,426	2,310	117***	4.8%	13.8%	117	4.8%	0	0.0%
Cooling		2,226	1,948	278***	12.5%	32.8%	278	12.5%	0	0.0%
Electric Heating (kWh)										
Baseload	320	8,871	8,294	577***	6.5%	26.3%	505	5.7%	72	0.8%
Heating		10,732	9,231	1,501***	14.0%	68.5%	1501	14.0%	0	0.0%
Cooling		1,235	1,121	114**	9.2%	5.2%	114	9.2%	0	0.0%
Gas Heat (ccf)										
Baseload	412	211	187	24***	11.3%	27.4%	24	11.3%	0	0.0%
Heating		982	918	63***	6.5%	72.6%	63	6.5%	0	0.0%
Education Only (kWh)										
Baseload	58	6,783	6,815	-33	0%	0%	-33	0.00%	0	0.0%
Heating		2,006	1,718	288*	14.3%	71.6%	288	14.3%	0	0.0%
Cooling		2,172	2,058	114	5.3%	28.4%	114	5.3%	0	0.0%

***Denotes significance at the 99 percent level. *Denotes significance at the 90 percent level.

Energy efficiency program savings are often found to correlate with the level of pre-treatment usage. This is because households with higher pre-treatment usage have greater opportunities for energy savings and often receive greater energy efficiency investments. Table IV-5 shows that the 2022 savings were generally consistent with this expectation.

- Baseload jobs with pre-treatment usage over 12,000 kWh had savings of 9.6 percent, compared to savings of 4.6 percent for baseload jobs with pre-treatment usage between 8,000 and 12,000 kWh.

- Electric heat jobs with pre-treatment usage over 26,000 kWh had average savings of 9.2 percent, while those jobs with pre-treatment usage between 16,000 and 26,000 kWh had savings of 11.2 percent, and jobs with usage below 16,000 kWh had savings of 10.8 percent. However the electric heat jobs with the highest pre-treatment usage had the highest kWh savings.

- Gas heat jobs with pre-treatment usage over 1,400 ccf saved an average of 175 ccf or 10.2 percent, those with pre-treatment usage between 800 and 1,400 ccf saved an average of 6.5 percent, and those with pre-treatment usage below 800 ccf had an increase in usage.

Table IV-5
Change in Annual Usage
By Pre-Program Usage

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
< 8,000 kWh	426	7,079	6,953	126*	1.8%	$412	41	0.6%	85	1.2%
8,000 – 12,000 kWh	1,023	9,781	9,336	446***	4.6%	$420	362	3.7%	84	0.9%
> 12,000 kWh	1,007	16,313	14,753	1,560***	9.6%	$588	1,478	9.1%	82	0.5%
Electric Heat (kWh)										
< 16,000 kWh	83	12,912	11,512	1,400***	10.8%	$3,174	1,327	10.3%	73	0.6%
16,000 – 26,000 kWh	171	20,642	18,336	2,306***	11.2%	$4,403	2,235	10.8%	71	0.3%
> 26,000 kWh	66	31,315	28,423	2,893***	9.2%	$4,233	2,820	9.0%	73	0.2%
Gas Heat[1] (ccf)										
< 800 ccf	52	725	732	-7	-1.0%	$2,329	-7	-1.0%	0	0.0%
800 – 1,400 ccf	257	1,112	1,039	72***	6.5%	$3,012	72	6.5%	0	0.0%
> 1,400 ccf	103	1,715	1,540	175***	10.2%	$3,125	175	10.2%	0	0.0%

***Denotes significance at the 99 percent level. * Denotes significance at the 90 percent level.
[1]Measure costs for gas heat jobs exclude the costs for the measures targeted at reducing electric usage.

Table IV-6 displays usage impacts by job type and by whether the household participated in CAP in the pre- or post-treatment period. Electric baseload savings were 741 kWh for CAP participants compared to 1,132 kWh for non-CAP participants. Gas heating savings were similarly higher for the non-CAP participants.

Table IV-6
Change in Annual Usage
By CAP Participation

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
CAP	1,792	12,172	11,431	741***	6.1%	$477	663	5.4%	78	0.6%
Non-CAP	664	11,501	10,369	1,132***	9.8%	$517	1,035	9.0%	97	0.8%
Electric Heat (kWh)										
CAP	237	21,275	19,084	2,191***	10.3%	$4,460	2,126	10.0%	65	0.3%
Non-CAP	83	19,591	17,395	2,196***	11.2%	$2,869	2,106	10.8%	90	0.5%
Gas Heat[1] (ccf)										
CAP	252	1,203	1,154	50***	4.1%	$2,587	50	4.1%	0	0.0%
Non-CAP	160	1,230	1,082	147***	12.0%	$3,531	147	12.0%	0	0.0%
Education Only (kWh)										
CAP	42	11,063	10,760	303	2.7%	--	303	2.7%	0	0.0%
Non-CAP	16	10,693	10,151	542	5.1%	--	542	5.1%	0	0.0%

***Denotes significance at the 99 percent level.
[1]Measure costs for gas heat jobs exclude the costs for the measures targeted at reducing electric usage.

Table IV-7 displays the change in usage by whether the customer had selected an alternate supplier in the pre or post period. Only a small percentage of customers had an alternate supplier. Electric baseload customers with an alternate supplier had significantly higher savings than those who did not and electric heating customers with an alternate supplier had lower savings.

Table IV-7
Change in Annual Usage
By Customer Choice

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Choice	165	11,588	10,416	1,172***	10.1%	$705	1,059	9.1%	113	1.0%
Non-Choice	2,291	12,020	11,196	824***	6.9%	$472	743	6.2%	81	0.7%
Electric Heat (kWh)										
Choice	20	19,764	18,316	1,448*	7.3%	$4,481	1,059	9.1%	113	1.0%
Non-Choice	300	20,910	18,668	2,242***	10.7%	$4,029	743	6.2%	81	0.7%
Gas Heat (ccf)										
Choice	74	1,252	1,122	130***	10.4%	$3,362	130	10.4%	0	0.0%
Non-Choice	338	1,205	1,127	79***	6.5%	$2,864	79	6.5%	0	0.0%
Education Only (kWh)										
Choice	2	8,660	6,867	1,793	20.7%	--	1,793	20.7%	0	0.0%
Non-Choice	56	11,043	10,725	318	2.9%	--	318	2.9%	0	0.0%

***Denotes significance at the 99 percent level.

Table IV-8 displays the change in usage by home ownership status. Owners had higher savings and measure costs than renters.

Table IV-8
Change in Annual Usage
By Home Ownership

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Owner	1,702	11,974	11,038	937***	7.8%	$562	852	7.1%	85	0.7%
Renter	754	12,028	11,384	645***	5.4%	$320	566	4.7%	79	0.7%
Electric Heat (kWh)										
Owner	177	21,423	18,750	2,673***	12.5%	$5,695	2591	12.1%	82	0.4%
Renter	143	20,115	18,518	1,597***	7.9%	$2,050	1538	7.6%	59	0.3%
Gas Heat[1] (ccf)										
Owner	308	1,218	1,120	98***	8.0%	$3,401	98	8.0%	0	0.0%
Renter	104	1,200	1,142	58***	4.9%	$1,630	58	4.9%	0	0.0%
Education Only (kWh)										
Owner	40	11,083	10,600	483*	4.4%	--	483	4.4%	0	0.0%
Renter	18	10,690	10,574	116	1.1%	--	116	1.1%	0	0.0%

***Denotes significance at the 99 percent level. *Denotes significance at the 90 percent level.
[1]Measure costs for gas heat jobs exclude the costs for the measures targeted at reducing electric usage.

Table IV-9 displays energy savings by whether the customer used supplemental heat. Average savings for electric baseload customers with supplemental heat were 8.7 percent, compared to six percent for baseload jobs without supplemental heat. Conversely, average savings for electric heating jobs with supplemental heat were 9.9 percent, compared to 10.8 percent for those without supplemental heat. Electric savings for gas heating jobs with supplemental heat were 10.1 percent compared to savings of 4.7 percent for those without supplemental heating.

Table IV-9
Change in Annual Usage
By Supplemental Heat

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Supplemental Heat	864	13,305	12,144	1,161***	8.7%	$590	1,077	8.1%	84	0.6%
No Supp Heat	1,592	11,278	10,601	677***	6.0%	$432	594	5.3%	83	0.7%
Electric Heat (kWh)										
Supplemental Heat	103	21,004	18,931	2,073***	9.9%	$4,331	1988	9.5%	85	0.4%
No Supp Heat	217	20,760	18,511	2,249***	10.8%	$3,928	2183	10.5%	66	0.3%
Gas Heat[1] (ccf)										
Supplemental Heat	148	1,236	1,158	78***	6.3%	$3,308	78	6.3%	0	0.0%
No Supp Heat	264	1,201	1,108	93***	7.7%	$2,755	93	7.7%	0	0.0%
Gas Heat[2] (kWh)										
Supplemental Heat	138	11,961	10,758	1,203***	10.1%	$3,052	1124	9.4%	79	0.7%
No Supp Heat	257	9,022	8,602	420***	4.7%	$2,737	324	3.6%	96	1.1%
Electric Baseload (ccf)										
Supplemental Heat	48	763	734	28	3.7%	$1,448	28	3.7%	0	0.0%
No Supp Heat	112	742	717	24**	3.3%	$746	24	3.2%	0	0.0%
Education Only (kWh)										
Supplemental Heat	13	13,182	12,397	784*	5.9%	--	784	5.9%	0	0.0%
No Supp Heat	45	10,320	10,070	249	2.4%	--	249	2.4%	0	0.0%
Education Only (ccf)										
Supplemental Heat	1	841	845	-4	-0.5%	--	-4	-0.5%	0	0.0%
No Supp Heat	3	742	720	22	2.9%	--	22	2.9%	0	0.0%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.
[1]Measure costs for gas heat jobs (ccf) exclude the costs for the measures targeted at reducing electric usage.
[2]Measure costs for gas heat (kWh) jobs exclude the costs for the measures targeted at reducing gas usage.

C. Measure Specific Savings

This section attributes savings to specific measures that were provided through LIURP. We begin by analyzing savings by whether major measures were provided. Major measures are defined as the following.

- Baseload Jobs: Major measures include refrigerator replacement, freezer replacement, air conditioner replacement, and water heater replacement.

- Electric Heat Jobs: Major measures include refrigerator replacement, freezer replacement, air conditioner replacement, water heater replacement, heat pumps, electric baseboards, insulation, and blower door guided air sealing.

- Gas Heat Jobs – Gas Measures: Major measures include furnace replacement, water heater replacement, insulation, and blower door guided air sealing.

- Gas Heat Jobs – Electric Measures: Major measures include refrigerator replacement, freezer replacement, and air conditioner replacement.

Homes that did not receive one of the major measures listed above were considered to have basic measures.

Table IV-10 displays energy savings by whether the job received one or more major measures.

- Baseload Jobs – Electric Savings: Savings for baseload jobs with major measures averaged 8.8 percent, compared to savings that averaged 6.4 percent for baseload jobs that did not receive major measures.

- Electric Heat Jobs: Savings for jobs that received major measures averaged 13.7 percent, compared to average savings of 6.1 percent for jobs that did not receive major measures. Spending on jobs that received major measures averaged $6,570, compared to average spending of $644 for jobs that did not receive major measures.

- Gas Heat Jobs – Gas Measures: Gas savings for jobs with major measures averaged 10.5 percent, compared to average savings of 5.7 percent for jobs that did not receive major measures. Costs for gas jobs with major measures averaged $7,119 compared to average costs of $833 for jobs that did not receive major measures.

- Gas Heat Jobs – Electric Measures: Savings for jobs that received major measures averaged 8.9 percent, compared to average savings of six percent for jobs that did not receive major measures. Costs for gas heat jobs that received major electric measures averaged $1,230 compared to average costs of $22 for jobs that did not receive major measures.

- Baseload Jobs – Gas Savings: Savings for jobs that received major measures averaged 3.3 percent, compared to an average savings of 3.5 percent for jobs that did not receive major measures.

Table IV-10
Change in Annual Usage
By Level of Service

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Basic	1,742	11,917	11,159	758***	6.4%	$135	675	5.7%	83	0.7%
Major	714	12,171	11,106	1,065***	8.8%	$1,347	981	8.1%	84	0.7%
Electric Heat (kWh)										
Basic	138	20,474	19,216	1,258***	6.1%	$644	1,188	5.8%	70	0.3%
Major	182	21,114	18,214	2,900***	13.7%	$6,570	2,827	13.4%	73	0.3%
Gas Heat[1] (ccf)										
Basic	273	1,239	1,169	70***	5.7%	$833	70	5.7%	0	0.0%
Major	139	1,164	1,042	122***	10.5%	$7,119	122	10.5%	0	0.0%
Gas Heat[2] (kWh)										
Basic	271	10,103	9,498	605***	6.0%	$22	514	5.1%	91	0.9%
Major	124	9,931	9,044	887***	8.9%	$1,230	800	8.1%	87	0.9%
Electric Baseload (ccf)										
Basic	129	739	713	26***	3.5%	$841	26	3.5%	0	0.0%
Major	31	786	761	26	3.3%	$1,439	26	3.3%	0	0.0%

***Denotes significance at the 99 percent level.
[1]Measure costs for gas heat (ccf) jobs exclude the costs for the measures targeted at reducing electric usage.
[2]Measure costs for gas heat (kWh) jobs exclude the costs for the measures targeted at reducing gas usage.

Table IV-11A displays savings for electric heat jobs by the number of major measures installed. The table shows that customers who received one or more major measures had higher pre-treatment usage and higher savings than customers who received no major measures. However, customers who received two or more major measures had approximately the same average savings as those with one major measure, despite having 80 percent higher measure costs.

Table IV-11A
Change in Annual Electric Heat Usage (kWh)
By Number of Major Measures

Major Measures	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Annual Savings	% Savings	Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
0	138	20,474	19,216	1,258***	6.1%	$644	1,188	5.8%	70	0.3%
1	89	20,777	17,900	2,877***	13.8%	$4,688	2,804	13.5%	73	0.3%
2 or More	93	21,437	18,515	2,922***	13.6%	$8,372	2,849	13.3%	73	0.3%

***Denotes significance at the 99 percent level.

Table IV-11B displays savings for gas heat jobs by the number of major measures installed. The table shows that customers who received one or more major measures had lower pre-treatment usage and higher savings than customers who received no major measures. Customers who received two or more major measures had the highest savings, averaging 153 ccf or 13.3 percent of pre-treatment usage.

Table IV-11B
Change in Annual Gas Heat Usage (ccf)
By Number of Major Measures

Major Measures	#	Pre-Use	Post-Use	Savings	% Savings	Measure Cost[1]
0	273	1,239	1,169	70***	5.7%	$833
1	86	1,172	1,069	103***	8.8%	$7,040
2 or More	53	1,151	997	153***	13.3%	$7,248

***Denotes significance at the 99 percent level.
[1]Measure costs for gas heat (ccf) jobs exclude the costs for the measures targeted at reducing electric usage.

Table IV-12 displays energy savings by whether participants received particular measures. Some of the key findings were as follows.

- *Air Conditioner*: Baseload customers who received an air conditioner had savings of 8.1 percent compared to savings of 6.7 percent for those who did not. Gas heating customers who received an air conditioner had higher savings (9.4%) compared to those who did not (6.1%).

- *Refrigerator*: Baseload participants who received a refrigerator had higher savings (11.9%) than those who did not (6.7%). Gas heating customers who received a refrigerator had higher savings (13.6%) compared to those who did not (6.3%).

- *Blower Door Guided Air Sealing:* Gas heating customers who received blower door guided air sealing had savings of 9.3 percent compared to savings of 6.9 percent for those

who did not. Electric heating customers who received blower door guided air sealing had higher savings (13.2%) than those who did not (9.9%).

- *Insulation:* Gas heating customers who received insulation had savings of nine percent compared to savings of seven percent for those who did not receive insulation. Electric heating customers who received insulation had higher savings (13.7%) than those who did not (9.5%).

- *Furnace:* Gas heating customers who received a new furnace had savings of 14.2 percent compared to 6.6 percent for those who did not.

Table IV-12
Change in Annual Usage
By Major Measures

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Savings	% Savings	Total Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Electric Baseload (kWh)										
Air Conditioner	625	11,899	10,937	962***	8.1%	$1,327	879	7.4%	83	0.7%
No Air Conditioner	1,831	12,022	11,214	808***	6.7%	$201	725	6.0%	83	0.7%
Refrigerator	134	13,728	12,091	1,638***	11.9%	$1,793	1,549	11.3%	89	0.6%
No Refrigerator	2,322	11,891	11,089	801***	6.7%	$412	718	6.0%	83	0.7%
Air Conditioner/ Refrigerator	56	13,635	12,138	1,497***	11.0%	$2,353	1,412	10.4%	85	0.6%
Air Conditioner/ No Refrigerator	569	11,728	10,819	909***	7.8%	$1,226	826	7.0%	83	0.7%
No Air Conditioner/ Refrigerator	78	13,796	12,057	1,739***	12.6%	$1,391	1,647	11.9%	92	0.7%
No Air Conditioner/ No Refrigerator	1,753	11,943	11,177	767***	6.4%	$148	684	5.7%	83	0.7%
Electric Heat (kWh)										
Refrigerator	28	20,934	18,933	2,000**	9.6%	$6,461	1,881	9.0%	119	0.6%
No Refrigerator	292	20,829	18,619	2,211***	10.6%	$3,824	2,144	10.3%	67	0.3%
Blower Door Test/Air Sealing	57	21,696	18,831	2,864***	13.2%	$7,251	2,799	12.9%	65	0.3%
No Blower Door Test or No Air Sealing	263	20,652	18,606	2,046***	9.9%	$3,354	1,973	9.6%	73	0.4%
Insulation	75	21,122	18,218	2,903***	13.7%	$8,194	2,839	13.4%	64	0.3%
No Insulation	245	20,752	18,777	1,974***	9.5%	$2,770	1,900	9.2%	74	0.4%

	#	Total Savings					LIURP Savings		Act 129 Savings	
		Usage		Savings	% Savings	Total Measure Cost	Annual Savings	% Savings	Annual Savings	% Savings
		Pre	Post							
Gas Heat[1] (ccf)										
Blower Door Test and Air Sealing	55	1,136	1,031	105***	9.3%	$5,724	105	9.3%	0	0.0%
No Blower Door Test or No Air Sealing	357	1,226	1,140	85***	6.9%	$2,527	85	6.9%	0	0.0%
Insulation	57	1,130	1,028	101***	9.0%	$5,668	101	9.0%	0	0.0%
No Insulation	355	1,227	1,142	86***	7.0%	$2,518	86	7.0%	0	0.0%
Furnace	34	1,160	995	165***	14.2%	$9,084	165	14.2%	0	0.0%
No Furnace	378	1,218	1,138	81***	6.6%	$2,402	81	6.6%	0	0.0%
Gas Heat[2] (kWh)										
Refrigerator	34	9,210	7,961	1,250***	13.6%	$1,509	1157	12.6%	93	1.0%
No Refrigerator	361	10,128	9,487	641***	6.3%	$297	551	5.4%	90	0.9%
Air Conditioner	99	9,947	9,014	933***	9.4%	$1,209	846	8.5%	87	0.9%
No Air Conditioner	296	10,083	9,470	613***	6.1%	$131	522	5.2%	91	0.9%
Electric Baseload (ccf)										
Air Conditioner	30	788	754	34	4.3%	$1,456	34	4.3%	0	0.0%
No Air Conditioner	130	739	715	24***	3.2%	$842	24	3.2%	0	0.0%
Refrigerator	4	623	690	-67	-10.7%	$1,801	-67	-10.8%	0	0.0%
No Refrigerator	156	751	723	28***	3.7%	$935	28	3.7%	0	0.0%
Air Conditioner/ Refrigerator	3	588	601	-14	-2.3%	$2,086	-14	-2.4%	0	0.0%
Air Conditioner/ No Refrigerator	27	811	771	39	4.8%	$1,386	39	4.8%	0	0.0%
No Air Conditioner/ Refrigerator	1	730	957	-226	-31.0%	$945	-226	-31.0%	0	0.0%
No Air Conditioner/ No Refrigerator	129	739	713	26***	3.5%	$841	26	3.5%	0	0.0%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.
[1]Measure costs for gas heat (ccf) jobs exclude the costs for the measures targeted at reducing electric usage.
[2]Measure costs for gas heat (kWh) jobs exclude the costs for the measures targeted at reducing gas usage.

Table IV-13A displays measure-specific savings estimates. These savings were calculated by running a regression model that predicted savings based on the measures that were provided. The table also shows the cost per unit saved, but those measures fully funded by Act 129 have no LIURP costs, so this information is not included for those measures.

In 2022, customers who only received LEDs and no other measures had average savings of 803 kWh. By comparison, in 2021, customers receiving only LEDs had average savings of 863 kWh.

The table also shows that refrigerators and freezers saved an average of 756 kWh per home. While the vast majority of refrigerators were funded through LIURP, some were funded through Act 129. Heat pumps installed in electric heat homes had average savings of 2,318 kWh.

Table IV-13A
Measure Savings Estimates

	Savings	Cost/Home	$/Unit Saved	Measure Life	$/Unit Saved Over Lifetime
Electric Baseload (kWh)					
LED Only[1]	803 (±303)	$316[2]	--	10	--
LED	8 (±6)	$0	$0.02	10	<$0.01
Refrigerator	756 (±230)	$1,171	$1.55	12	$0.17
Freezer	756 (±230)	$267	$0.35	12	$0.04
Air Conditioner	108 (±120)	$885	$8.20	13	$0.87
Gas Heat (ccf)					
Gas Furnace	74 (±36)	$5,663	$76.52	15	$7.37
Boiler	79 (±39)	$11,030	$139.62	15	$13.45
Electric Heat (kWh)					
LED	24 (±20)	$1,011	$42.13	10	$5.46
Air Conditioner	1,521 (±727)	$658	$0.43	13	$0.05
Water heater	665 (±804)	$628	$0.94	12	$0.11
Air sealing only	1,030 (±854)	$1,237	$1.20	15	$0.12
Air sealing and insulation	713 (±530)	$3,539	$4.96	15	$0.48
Heat Pump	2,318 (±495)	$6,085	$2.63	15	$0.25

[1]The average number of LEDs provided to these customers was 11.5.
[2]This is the cost for the audit and education of customers who only received LEDs. The cost for the LEDs is paid for by the Act 129 Program.

Table IV-13B displays the savings for jobs that received health and safety measures other than carbon monoxide detectors and smoke alarms and batteries. The table shows that baseload and gas heat jobs had higher energy savings than jobs overall. Savings averaged 1,471 kWh for baseload jobs with health and safety measures, compared to 847 kWh overall. Savings averaged 1,225 kWh for electric heating jobs (not statistically significant due to the small sample size), lower than electric heating job savings overall. Additionally, gas heating jobs achieved average savings of 97 ccf compared to savings of 88 ccf for all gas heating jobs.

Table IV-13B
Degree Day-Normalized Usage and Savings
Jobs with Health & Safety Measures

Job Type	#	Pre	Post	Savings	
				#	%
Electric Baseload (kWh)	86	13,697	12,227	1,471***	10.7%
Electric Heat (kWh)	24	22,506	21,281	1,225	5.4%
Gas Heat (ccf)	29	1,043	946	97***	9.3%

***Denotes significance at the 99 percent level.

D. Cost Effectiveness

This section examines the cost-effectiveness of the Program services delivered by job type. Audit and administrative costs were assigned to electric and gas costs in the same proportion as the measure costs. Table IV-14 shows the measure costs, audit/education costs, and administrative costs by job type and electric and gas reduction. Cost per unit saved was calculated as the average total cost divided by the unit savings. The cost per kWh saved was $1.05 for baseload jobs and $2.05 for electric heat jobs. The cost per ccf saved was $38.34 for gas heat jobs.

Table IV-14
Cost per Unit Saved

	#	Average Savings	Average Measure Cost	Average Audit/ Education Cost	Average Admin Cost	Average Total Cost	Cost Per Unit Saved
Electric Baseload							
Electric (kWh)	2,456	847	$428	$303	$155	$887	$1.05
Gas (ccf)	160	26	$644	$190	$97	$931	$35.80
Electric Heat							
Electric (kWh)	320	2192	$4,026	$316	$162	$4,503	$2.05
Gas Heat							
Electric (kWh)	395	693	$402	$38	$19	$459	$0.66
Gas (ccf)	412	88	$2,954	$278	$142	$3,374	$38.34

The previous analysis displayed the total job cost divided by the total savings as an indicator of how cost-effective the services were. Table IV-15 displays the discounted present value of the job savings under 5-year, 10-year and 15-year measure life assumptions. The costs per unit saved should be compared to retail rates to evaluate the cost-effectiveness of the Program at different measure life values.

The most reasonable assumption for electric baseload reduction is a ten-year measure life. Current electricity costs are approximately $0.17 per kWh. This table shows that the electric

baseload investments were cost-effective in 2022, given that the cost per unit saved was slightly lower than the retail rate.

The most reasonable assumption for gas heating is a 15-year measure life. Under the 15-year measure life assumption, the cost per ccf saved is $3.69, which is not cost-effective. The cost to save a ccf of gas would need to be lower than the price for a ccf for LIURP to be cost-effective. Since the current gas cost is approximately $0.99 per ccf, LIURP would need to increase the savings that were obtained from the measures that were installed to be cost-effective.

Table IV-15
Cost Per Unit Saved
By Measure Life Assumption

	#	Average Savings	Average Total Cost	Cost Per Unit Saved	5-Year Measure Life	10-Year Measure Life	15-Year Measure Life
Electric Baseload							
Electric (kWh)	2,456	847	$887	$1.05	$0.24	$0.14	$0.10
Gas (ccf)	160	26	$931	$35.80	$8.27	$4.64	$3.45
Electric Heat							
Electric (kWh)	320	2,192	$4,503	$2.05	$0.47	$0.27	$0.20
Gas Heat							
Electric (kWh)	395	693	$459	$0.66	$0.15	$0.09	$0.06
Gas (ccf)	412	88	$3,374	$38.34	$8.86	$4.97	$3.69

V. Bill and Payment Impacts

This section of the report examines the bill and payment impacts for the 2022 LIURP participants. We review the methodology used in the analysis, and then analyze the billing and payment impacts.

A. Methodology

Billing and payment transactions data were used to analyze the pre- and post-treatment billing and payment statistics. Accounts were required to have between 300 and 390 days of transactions data in both the pre and post periods to be included in the analysis.

Table V-1 displays the data attrition statistics. Overall, sufficient data were available for 49 percent of Program participants.

Table V-1
Payment Impact Data Attrition

	Electric Baseload	Electric Heating	Gas Heating	Education Only	All Jobs
Original Population	2,715	394	476	82	3,667
No Transactions Data	0	0	1	0	1
Not Enough Pre-Treatment Days	789	223	260	9	1,281
Not Enough Post-Treatment Days	237	25	27	12	301
Data Outliers	149	47	54	20	270
Final Sample	1,540	99	134	41	1,814
% Included in Analysis	57%	25%	28%	50%	49%

Note: For Table V-2 only, the final sample included in the analysis is 1,668 accounts (45% of the original population), this was due to a smaller number of accounts with complete revenue data.

B. Billing and Payment Impacts

Table V-2 displays the billing revenue data obtained from the usage file. Not all accounts with 300 to 390 days of usage data for the analysis had revenue data for the whole period. Table V-2 includes only accounts that had between 300 and 390 days of usage and revenue data. There were 1,668 accounts that had enough pre-treatment and post-treatment days with revenue data, which represents 45 percent of the original population and 92 percent of the financial analysis group. These data show the changes in charges that were associated with electric and gas usage only. For example, charges related to service agreements or late payment charges would not be included in this table.

Table V-2 shows that electric revenue decreased by an average of $205 for baseload jobs and by $431 for electric heat jobs. Gas revenue decreased by $62 for gas heat jobs.

Table V-2
Billing Revenue

	#	Pre	Post	Change	Percent Change
Electric Baseload					
Electric Revenue	1,435	$937	$733	-$205***	-21.8%
Gas Revenue		$40[1]	$39[1]	-$1	-3.4%
Total Revenue		$978	$772	-$206***	-21.1%
Electric Heat[2]					
Electric Revenue	85	$1,658	$1,227	-$431***	-26.0%
Gas Revenue		$3	$2	-$1	-22.0%
Total Revenue		$1,661	$1,230	-$432***	-26.0%
Gas Heat					
Electric Revenue	108	$946	$888	-$58	-6.1%
Gas Revenue		$694	$632	-$62**	-8.9%
Total Revenue		$1,640	$1,520	-$120**	-7.3%
Education Only					
Electric Revenue	40	$884	$668	-$216***	-24.4%
Gas Revenue		$55	$66	$11	20.2%
Total Revenue		$938	$734	-$205***	-21.8%
All Job Types					
Electric Revenue	1,668	$973	$767	-$207***	-21.3%
Gas Revenue		$81	$76	-$5**	-6.1%
Total Revenue		$1,055	$843	-$212***	-20.1%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level.
[1]Only 31 Electric Baseload accounts have gas usage data.
[2]Only 1 Electric Heat account has gas usage data.

Table V-3A displays the change in customer electric and gas bills and total charges, between the pre- and the post-treatment periods, based on analysis of the transactions file. Total charges decreased by 10.0 percent for electric baseload jobs, 10.9 percent for electric heat jobs, and 0.5 percent for gas heat jobs. Total charges decreased by 9.1 percent for all job types.

Differences in results between the revenue analysis from the billing data (shown in Table V-2) and the billing analysis from the transactions data (shown in Table V-3A) are due to the fact that the transactions data include all charges, while the revenue data only include charges for electric and gas usage.

Table V-3A
Bills and Total Charges

	#	Pre	Post	Change	Percent Change
Electric Baseload					
Electric and Gas Charges	1,540	$1,138	$1,020	-$119***	-10.4%
Other Charges		$10	$14	$4***	39.4%
Total Charges		$1,149	$1,034	-$115***	-10.0%
Electric Heat					
Electric and Gas Charges	99	$1,828	$1,625	-$203***	-11.1%
Other Charges		$23	$25	$2	7.3%
Total Charges		$1,851	$1,650	-$201***	-10.9%
Gas Heat					
Electric and Gas Charges	134	$1,898	$1,874	-$24	-1.3%
Other Charges		$18	$33	$14	78.9%
Total Charges		$1,916	$1,906	-$10	-0.5%
Education Only					
Electric and Gas Charges	41	$1,071	$889	-$182***	-17.0%
Other Charges		$1	$3	$2	133.0%
Total Charges		$1,072	$892	-$181***	-16.8%
All Job Types					
Electric and Gas Charges	1,814	$1,231	$1,113	-$118***	-9.6%
Other Charges		$11	$16	$5***	40.8%
Total Charges		$1,242	$1,129	-$113***	-9.1%

***Denotes significance at the 99 percent level.

Table V-3B displays bills and total charges for customers who had CAP rates for the full pre-period and for the full post-treatment period. The table shows that across all job types, total charges decreased by 20.2 percent for this population, compared to the 9.1 percent decrease overall, as shown in the previous table.

Table V-3B
Bills and Total Charges
Customers with CAP Rates In All Pre and Post Periods

	#	Pre	Post	Change	Percent Change
Electric Baseload					
Electric and Gas Charges	1,077	$995	$775	-$221***	-22.2%
Other Charges		$7	$9	$2	32.2%
Total Charges		$1,002	$784	-$218***	-21.8%

	#	Pre	Post	Change	Percent Change
Electric Heat					
Electric and Gas Charges	69	$1,662	$1,357	-$305***	-18.4%
Other Charges		$18	$8	-$10	-55.3%
Total Charges		$1,681	$1,365	-$315***	-18.8%
Gas Heat					
Electric and Gas Charges	78	$1,714	$1,538	-$175***	-10.2%
Other Charges		$5	$26	$21**	403.4%
Total Charges		$1,719	$1,564	-$154**	-9.0%
Education Only					
Electric and Gas Charges	31	$1,011	$826	-$186***	-18.3%
Other Charges		$1	$2	$1	-84.0%
Total Charges		$1,012	$828	-$185***	-18.2%
All Job Types					
Electric and Gas Charges	1,255	$1,077	$855	-$222***	-20.6%
Other Charges		$7	$10	$3*	36.5%
Total Charges		$1,084	$866	-$219***	-20.2%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.

Table V-4 displays payment statistics for the 2022 LIURP participants. Across all job types, total credits decreased by $115 from the pre-treatment year to the post-treatment year.

Table V-4
Annual Payments
Pre- and Post-LIURP Treatment

	#	Pre	Post	Change	Percent Change
Electric Baseload					
# Payments	1,540	8.9	8.5	-0.4***	-4.2%
Cash Payments		$1,035	$949	-$86***	-8.3%
Assistance Payments		$103	$90	-$13*	-12.8%
Other Credits		$10	$5	-$4***	-44.1%
Total Credits		$1,148	$1,044	-$104***	-9.0%
Electric Heat					
# Payments	99	8.8	8.6	-0.2	-2.1%
Cash Payments		$1,541	$1,368	-$172**	-11.2%
Assistance Payments		$334	$208	-$127***	-37.9%
Other Credits		$12	$2	-$10**	-87.0%
Total Credits		$1,887	$1,577	-$310***	-16.4%

	#	Pre	Post	Change	Percent Change
Gas Heat					
# Payments	134	8.9	8.4	-0.5*	-5.5%
Cash Payments		$1,667	$1,642	-$25	-1.5%
Assistance Payments		$342	$316	-$26	-7.7%
Other Credits		$11	$8	-$3	-26.7%
Total Credits		$2,020	$1,966	-$55	-2.7%
Education Only					
# Payments	41	10.4	9.4	-1.0***	-10.0%
Cash Payments		$1,007	$773	-$235***	-23.3%
Assistance Payments		$115	$78	-$38	-32.7%
Other Credits		$1	$1	-$1	-53.4%
Total Credits		$1,124	$851	-$273***	-24.3%
All Job Types					
# Payments	1,814	8.9	8.5	-0.4***	-4.3%
Cash Payments		$1,109	$1,019	-$90***	-8.1%
Assistance Payments		$134	$113	-$21***	-15.7%
Other Credits		$10	$5	-$4***	-45.6%
Total Credits		$1,252	$1,137	-$115***	-9.2%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.

Table V-5 displays payments for CAP and non-CAP customers in the year prior to and after receipt of LIURP. For CAP customers across all job types, total credits decreased by $191. For non-CAP Customers across all job types, total credits increased by $77.

Table V-5
Payments for CAP Customers
Pre- and Post-LIURP Treatment

	#	Pre	Post	Change	Percent Change
CAP Customers – All Job Types					
# Payments	1,302	8.5	8.1	-0.5***	-5.3%
Cash Payments		$916	$764	-$152***	-16.2%
Assistance Payments		$158	$124	-$34***	-21.6%
Other Credits		$9	$5	-$4***	-46.6%
Total Credits		$1,084	$894	-$191***	-17.6%
Non-CAP Customers – All Job Types					
# Payments	512	9.8	9.6	-0.2	-2.1%
Cash Payments		$1,597	$1,666	$68**	4.3%
Assistance Payments		$71	$84	$13	18.6%

	#	Pre	Post	Change	Percent Change
Other Credits		$10.9	$6.2	-$4.7*	-43.3%
Total Credits		$1,679	$1,755	$77**	4.6%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.

Table V-6 displays a more detailed analysis of the types of assistance payments received by the 2022 LIURP participants in the pre- and the post-treatment periods. The table shows that, across all job types, total assistance payments decreased by an average of $21 from the pre-treatment year to the post-treatment year.

Table V-6
Assistance Payments
Pre and Post-LIURP Treatment

	#	Pre	Post	Change	% Change
Electric Baseload					
LIHEAP Cash	1,540	$84	$70	-$14**	-16.7%
LIHEAP Crisis		$19	$20	$1	4.3%
MEAF		$0	$0	$0	0.0%
Total Assistance		$103	$90	-$13*	-12.8%
Electric Heat					
LIHEAP Cash	99	$276	$202	-$74**	-26.8%
LIHEAP Crisis		$58	$5	-$53**	-91.0%
MEAF		$0	$0	$0	0.0%
Total Assistance		$334	$208	-$127***	-37.9%
Gas Heat					
LIHEAP Cash	134	$284	$291	$7	2.4%
LIHEAP Crisis		$58	$25	-$33*	-57.5%
MEAF		$0	$0	$0	0.0%
Total Assistance		$342	$316	-$26	-7.7%
Education Only					
LIHEAP Cash	41	$81	$78	-$3	-4.3%
LIHEAP Crisis		$34	$0	-$34	-100.0%
MEAF		$0	$0	$0	0.0%
Total Assistance		$115	$78	-$38	-32.7%

	#	Pre	Post	Change	% Change
All Job Types					
LIHEAP Cash	1,814	$109	$94	-$15***	-14.2%
LIHEAP Crisis		$24	$19	-$5	-22.1%
MEAF		$0	$0	$0	0.0%
Total Assistance		$134	$113	-$21***	-15.7%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level. *Denotes significance at the 90 percent level.

Table V-7 displays changes in cash and total bill coverage[14] rates between the pre- and the post-treatment periods. On average, the cash coverage rate and the total coverage rate increased by 0.6 percentage points and 0.7 percentage points respectively for all job types.

Table V-7
Coverage Rates
Pre- and Post-LIURP Treatment

	#	Pre	Post	Change	Percent Change
Electric Baseload					
Cash Coverage Rate	1,540	90.6%	92.0%	1.4%	1.5%
Total Coverage Rate		102.3%	104.1%	1.8%	1.7%
Electric Heat					
Cash Coverage Rate	99	79.2%	77.2%	-2.0%	-2.5%
Total Coverage Rate		102.0%	95.7%	-6.3%*	-6.2%
Gas Heat					
Cash Coverage Rate	134	85.6%	81.3%	-4.3%	-5.0%
Total Coverage Rate		108.2%	104.6%	-3.7%	-3.4%
Education Only					
Cash Coverage Rate	41	97.6%	88.8%	-8.8%	-9.0%
Total Coverage Rate		108.0%	98.0%	-10.0%	-9.3%
All Job Types					
Cash Coverage Rate	1,814	89.8%	90.4%	0.6%	0.6%
Total Coverage Rate		102.8%	103.5%	0.7%	0.6%

*Denotes significance at the 90 percent level.

[14] The cash coverage rate is the amount of cash payments made divided by the bill. The total coverage rate is the total of all customer payments, customer assistance, and other credits divided by the bill.

Table V-8 displays changes in customer balances. While balances from the beginning to the end of the pre-treatment period declined by 3.9 percent, balances from the beginning to the end of the post-treatment period declined by 28.2 percent.

Table V-8
Change in Customer Balance

	#	Start	End	Change	Percent Change
Electric Baseload					
Pre Balance	1,540	$138	$144	$6	4.4%
Post Balance		$140	$102	-$38***	-27.2%
Electric Heat					
Pre Balance	99	$194	$150	-$44	-22.6%
Post Balance		$151	$136	-$15	-10.0%
Gas Heat					
Pre Balance	134	$243	$143	-$100**	-41.0%
Post Balance		$226	$125	-$102***	-44.9%
Education Only					
Pre Balance	41	$100	$48	-$52	-52.2%
Post Balance		$52	$42	-$10	-18.8%
All Job Types					
Pre Balance	1,814	$148	$142	-$6	-3.9%
Post Balance		$145	$104	-$41***	-28.2%

***Denotes significance at the 99 percent level. **Denotes significance at the 95 percent level.

VI. Summary of Findings and Recommendations

PECO's LIURP delivered usage reduction services and energy education to over 3,500 customers in 2022, many of whom had vulnerable household members. The program performed significantly better than recent years in terms of energy savings from electric heating jobs and gas heating jobs. Savings from electric heating jobs averaged 10.5 percent, compared to recent years that had savings below six percent. Savings from gas heating jobs were 7.2 percent compared to recent years that were all below five percent and often below three percent. Savings from electric baseload jobs were in line with the 20-year historic average. When accounting for the comparison group change, both electric baseload and electric and gas heating net savings were even higher compared to recent years.

The average measure cost remained more than double the historic average and stable compared to the previous year, which reduced the cost-effectiveness of LIURP. The increase in job costs was likely driven by rising material and labor costs stemming from the inflationary environment in the post-COVID economy. These cost increases are expected to continue to impact the program in future years.

We have the following recommendations to improve energy savings and the cost-effectiveness of LIURP.

- *Outreach:* While CMC was successful in increasing the number of contacted customers to pre-COVID levels, most customers did not respond to contact attempts. The current procedure is to make at least three phone calls and send a follow-up letter.[15] CMC should increase the number of calls to high-usage customers and pilot additional methods of outreach to targeted neighbors when they are in the field, such as leaving door hangers. PECO is continuing work with CMC to expand and improve LIURP outreach.

- *Targeting High Users:* The savings for electric baseload and gas heating jobs are significantly higher for customers with higher pre-program usage. CMC was successful in 2022 in reaching higher usage customers than in some of the other recent years. They should continue to target higher usage households and focus on deploying major measures to homes where they are likely to maximize impact.

- *Major Measure Installation*: Savings on jobs with more major measures are significantly higher. CMC was successful in increasing the rate of air sealing and insulation on electric heating jobs compared to recent years. They were also successful in installing heat pumps in a greater percentage of homes. These changes lead to historic savings for the electric heating jobs. However, electric and gas heating job still have low levels of air sealing and insulation. CMC should work to increase the rate of air sealing and insulation work on both electric and gas heating jobs.

[15] This is PECO's minimum standard for the number of contact attempts.

- *Health and Safety Remediation:* The health and safety component of the LIURP program has been effective at allowing additional energy saving measures to be installed through health and safety work. PECO should consider expanding their health and safety program by providing additional remediation work (such as electrical upgrades) that would enable energy efficiency measures in older homes.

PECO ENERGY COMPANY
STATEMENT NO. 10-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2024-3046931

SURREBUTTAL TESTIMONY

WITNESS: JAQUELINE F. GOLDEN

SUBJECT: CUSTOMER SERVICE AND SATISFACTION

DATED: AUGUST 2, 2024

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SURREBUTTAL TESTIMONY
OF
JAQUELINE F. GOLDEN

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name, professional position, and business address.

A. My name is Jacqueline F. Golden. I am employed by PECO Energy Company ("PECO" or the "Company") as the Director of Customer Financial Operations. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. Yes. I submitted direct and rebuttal testimony on behalf of the Company, which are designated as PECO Statement Nos. 10 and 10-R, respectively.

3. Q. Do you have any corrections to make to your rebuttal testimony?

A. Yes. On page 21, line 13 of my rebuttal testimony, "will contract with" should be replaced with "will contact." The complete, corrected sentence reads: "If a customer is a renter, the LIURP contractor will contact the property owner and provide a consent form and self-addressed postage paid envelope."

4. Q. What is the purpose of your rebuttal testimony?

A. My surrebuttal testimony will address supplemental direct testimony provided by Office of Consumer Advocate ("OCA") witness Nicolas A. DeMarco regarding certain customer service issues raised at the public input hearings in this case. I will also respond to the recommendations of Lawrence Anastasi on behalf of the Local 614 of the International Brotherhood of Electrical Workers, AFL-CIO

("Local 614") to provide additional training to PECO's customer service representatives ("CSRs") as the Company works through the implementation of the new customer service software ("Customer Care and Billing" or the "CC&B").[1]

II. ISSUES RAISED IN PUBLIC INPUT HEARINGS

5. Q. Mr. DeMarco highlighted a concern raised by Ms. Liz Robinson at the June 13, 2024 afternoon public input hearing related to the accuracy of her monthly bill as a virtual meter aggregation customer. Has PECO responded to that concern?

A. Yes. A Company representative reached out to Ms. Robinson to discuss her bill. The representative explained that although the bill did not display solar generation information as it relates to her virtual meter aggregation, the amount due on the bill was correct. Ms. Robinson was satisfied with the explanation and did not have additional questions about her bill.

6. Q. In an exhibit summarizing selected public input hearing testimony (OCA Exhibit NAD-1-SD), Mr. DeMarco notes a concern raised by Ms. Mary Kay Owen at the June 13, 2024 afternoon public input hearing related to an increase in her budget bill payments. Has PECO responded to that concern?

A. Yes. A Company representative spoke with Ms. Owen about her budget bill concerns. The representative explained how the budget billing amounts are calculated, when they are reviewed, and the impact actual usage has on the

[1] Mr. Anastasi mistakenly refers to the new customer service software as "CCMV" throughout his rebuttal testimony. Here, I will refer to the new customer service software as CC&B rather than CCMV.

adjustment of budget bill amounts. Ms. Owen was also offered a Home Energy Audit (to check for energy efficiency opportunities) and a High Bill Field Visit (to justify the usage being billed based on appliances in the home). Ms. Owen declined those offers but appreciated the Company's call.

III. CUSTOMER SERVICE REPRESENTATIVE ("CSR") TRAINING

7. Q. Could you please summarize Mr. Anastasi's concerns regarding the Company's training of CSRs in response to Question 17 of his rebuttal testimony?

A. Yes. First, I would like to highlight that Mr. Anastasi begins his answer by applauding PECO's efforts to address customer service by hiring approximately two hundred (200) additional CSRs in August and September of 2023. Despite this significant effort, he expresses concerns that: (1) CSR supervisors need additional training to provide adequate support and knowledgeable feedback to CSRs; (2) CSRs were not given adequate training and time to practice use of the new customer service software ("CC&B"), nor were they given "cheat sheets" to know where to assess information when handling customer calls; (3) the Company has inappropriately reduced the amount of training provided to CSRs to handle credit and collections calls and supervisors are not available to answer questions; and (4) there is a spike in the number of customers calls due to billing exceptions related to the CC&B software which has caused "great stress and pressure on CSRs" and caused unplanned mandatory overtime.

8. Q. How do you respond to his concerns?

A. I do not agree with the concerns raised in his rebuttal testimony given the extensive training that the Company provided to CSRs in anticipation of the software transition. The Company's training approach for the CSRs followed industry best practices and was broken out across three phases, intentionally starting early in the project timeline, and continuing up until CC&B was put into service.

The first phase of training, "Set the Foundation", began in February 2022 and concluded in October 2022. This phase introduced CSRs to core CC&B concepts like the V-Model and included thirty (32) video demonstrations and training materials which are accessible to CSRs via the project's New Horizons Resource Hub.

The second phase of the training, "Make it Real", began in February 2023 and concluded in July 2023. This phase of training consisted of twenty-six (26) courses, focused on core processes that CSRs would need to follow in CC&B. Notably, approximately three hundred seventy-five (375) job aids were created to accompany these twenty (26) courses, all of which are accessible to CSRs via the project's New Horizons Resource Hub. In addition, answers to questions CSRs asked in Make It Real were posted on the New Horizons Resource Hub.

The third phase of the training, "Practice and Prepare", began in September 2023 and concluded in January 2024. This phase of training consisted of practice labs and refresher training on key topics. Many of these topics were solicited from

CSRs themselves. Notably, one hundred percent (100%) of the CSRs completed this Practice and Prepare phase of the training.

9. Q. Did PECO solicit and receive feedback from the CSRs upon completion of the training?

A. Yes, we did, and I am happy to report that the survey results were positive. For example, the Practice & Prepare survey questions and results are as follows:

- The activities in the class helped me learn the materials: 4.78 out of 5.
- The course material was clear and easy to follow: 4.7 out of 5.
- I was given enough time to learn and practice the intended knowledge and skills: 4.74 out of 5.
- I thought the instructor facilitated the session in a clear and organized manner: 4.88 out of 5.
- I felt engaged during the session because the instructor recognized the students' needs: 4.88 out of 5.
- I thought the knowledge check related directly to the practice scenario: 4.82 out of 5.
- I would recommend this training to my peers: 4.77 out of 5.

In response to Mr. Anastasi's comments about pressure on CSRs, while it is true that CSR responsibility includes mandatory overtime to support the business as needed in accordance with the existing collective bargaining agreement and PECO makes best efforts to provide as much advanced notice as possible, the Company

does recognize the challenges that the CSRs have experienced with the transition to CC&B. In fact, for the limited period of system roll-out, CSRs were not held accountable for the performance on their score cards. Fortunately, the Company has made significant progress resolving exceptions and the CSRs quickly have built proficiency levels that should have reduced stress levels. Moreover, once a CSR can demonstrate proficiency with CC&B, that CSR is allowed to return to a nearly fully remote-hybrid work schedule. Most CSRs returned to a hybrid work schedule by the end of June. The CSRs are part of the only department at PECO that is permitted to be fully remote except for occasional in-office requirements.

Finally, I note that PECO makes every effort to ensure that supervisors are provided with required leadership skills to support the CSRs. With respect to CC&B specific support, PECO has created and is in the process of implementing additional CC&B training for front line supervisors and coaches to enable them to be a reliable resource to support the CSRs in real time. This additional training for supervisors and coaches be completed by the end of the year. However, it should be noted that coaches were trained on CC&B at the same time as the CSRs and are readily available to provide support today.

IV. CONCLUSION

10. Q. Does this complete your surrebuttal testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2024-3046931**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Jacqueline F. Golden, hereby state that I am the Director of Customer Financial Operation for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked statements and exhibits listed below are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

- PECO Statement No. 10
- PECO Statement No. 10-R
- PECO Exhibit JFG-1
- PECO Statement No. 10-SR

Dated: August 7, 2024

Jacqueline F. Golden