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March 22, 2023

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VIA ELECTRONIC FILING

Andrew S. Johnston, Executive Secretary
Maryland Public Service Commission
William Donald Schaefer Tower, 16th Floor
6 St. Paul Street
Baltimore, Maryland 21202

Re: Application of The Potomac Edison Company for Adjustments to its Retail Rates for the Distribution of Electric Energy

Dear Executive Secretary Johnston:

The Potomac Edison Company ("PE" or the "Company") hereby files electronically this date its Application for Adjustments to its Retail Rates for the Distribution of Electric Energy.

As required by the provisions of the Code of Maryland Regulations ("COMAR") 20.07.04.07, the Company concurrently files herewith sixteen pieces of Direct Testimony and Exhibits of its witnesses: Raymond E. Valdes, Stephanie L. Fall, Donald J. McGettigan, Weizhong (Bill) Wang, Gregory J. Gawlik, Susan M. Colflesh, Bobbi S. Miller, Jill A. Soltis, Heather E. Ward, Tracy M. Ashton, Walter S. Larnerd, Dylan W. D'Ascendis, Timothy S. Lyons,[1] John J. Spanos, and Mark Warner.

As described further in the Application and Direct Testimony, PE's request for adjustment to retail rates includes a request for the approval of two new innovative low-income assistance initiatives in accordance with the Maryland Code's Public Utilities Article ("PUA") § 4-309. Pursuant to PUA § 4-309(d)(1)(ii), and as set forth in PE's Application, PE is seeking prior approval from the Commission to consider these low-income assistance initiatives as part of this rate case filing.

In addition, the Company files with this Application the Supplemental Information required by the Commission's April 18, 1983 Secretarial Letter Order. Certain portions of the Supplemental Information are Confidential and will be filed separately.

Although the Commission's March 16, 2020 Operational Notice has waived the requirement to provide paper copies of this filing, PE will provide a limited number of paper copies

[1] Mr. Lyons will be providing two pieces of testimony: one regarding cash working capital, and one regarding the Company's class cost of service ("CCOS") and rate design.

of this filing as a courtesy to the Commission. The Maillog number assigned to this filing will be indicated above for your reference.

If you need additional information or have any questions, please do not hesitate to contact me.

Respectfully submitted,

J. Joseph Curran, III

Enclosures
Cc: Jeffrey Trout, The Potomac Edison Company
Jessica Raba, The Potomac Edison Company
Lloyd Spivak, Staff Counsel
David Lapp, People's Counsel

BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

In the Matter of the Application	*	
Of the Potomac Edison Company	*	
For Adjustments to its Retail	*	**Case No. ______**
Rates for the Distribution of	*	
Electric Energy	*	

APPLICATION OF THE POTOMAC EDISON COMPANY FOR ADJUSTMENTS TO ITS RETAIL RATES FOR THE DISTRIBUTION OF ELECTRIC ENERGY

The Potomac Edison Company ("PE" or "the Company"), a public service company under the Public Utilities Article of the Annotated Code of Maryland ("PUA"), herein applies for authority to adjust its retail rates for the distribution of electric energy in its Maryland service territory pursuant to PUA §§ 4-203 and 4-204. All correspondence and communications concerning this matter should be sent to the following persons at the addresses stated below:

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Through this Application, PE seeks an increase of distribution rates to recover the costs of the Company's ongoing efforts to provide safe and reliability service to its customers in a cost-effective manner. PE's request also includes the costs of important service and state-policy initiatives, including but not limited to: moving the costs of past Electric Distribution Investment Surcharge ("EDIS") projects into rate base, as directed by the Commission in the Company's last rate case order, as well as proposing a Phase II of EDIS to continue proactive investments in system reliability and resiliency; recovery of costs for the Electric Vehicle charging pilot program (Case No. 9478); recovery of costs for the Commission's and the Company's responses to protect customers, PE employees, and the integrity of the distribution system during the COVID pandemic; and two new initiatives, undertaken in response to recent Maryland legislation, to provide further assistance to the Company's low-income customers.

PE files herewith certain adjustments to its electric base rates and other revisions to its Electric Service Tariffs to become effective on April 22, 2023. In support of its application, PE states as follows:

Description of PE

1. PE is a public service company subject to regulation by the Maryland Public Service Commission ("Commission") pursuant to § 2-112 of the PUA.

2. Currently, PE provides electric service to approximately 285,000 customers in Maryland, across a service territory of 2,547 miles. PE's service territory covers approximately 26% of Maryland's land mass and includes all or parts of Allegany, Carroll, Frederick, Garrett,

Howard, Montgomery, and Washington counties and 41 municipalities. PE's unique service territory is a combination of suburban, rural, and mountainous terrain and demographics.

Requested Increase in Rates

3. Under the provisions of PUA § 5-303, PE has the affirmative duty to furnish utilities, services, and facilities which are safe, adequate, just, reasonable, economical and efficient.

4. In order to continue to meet its obligation to provide safe and adequate service, PE must continuously replace and enhance its distribution system infrastructure and must also continue to make substantial investments in infrastructure and have a reasonable opportunity to recover its costs. The costs in this case cover investments since PE's last base rate case, as well as planned spending on reliability in 2023 and beyond.

5. Since its last request for a rate increase filed in 2018, PE has made substantial investments in its infrastructure. These capital investments in PE's distribution system are producing positive results for the Company and for its customers; PE's metrics in System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") performance have seen continuous improvement, particularly since 2019 with the implementation of PE's EDIS program. For example, as reported in the most recent customer perception survey required and supervised by the Commission under COMAR 20.50.12.14.C, 86% of PE's residential customers and 80% of its commercial customers expressed overall satisfaction with the Company's performance. Moreover, as the annual service reliability reports filed by PE pursuant to COMAR 20.50.12.11 indicate, the Company has continuously met or exceeded most or all of the goals for various measures of service quality set by the Commission in each of the years since PE's last base rate case. However, PE must continue to invest in its distribution system

in order to maintain and improve on its reliability performance. Thus, PE has proposed three specific incremental infrastructure improvements to its electric distribution system which, if approved, would form the EDIS Part II, *i.e.*, a continuation of the modest reliability surcharge (EDIS) that the Commission approved as a part of PE's most recent base rate case (Case No. 9490). The testimony and exhibits supporting this Application provide support for EDIS Part II's implementation.

6. PE is also proposing for the Commission's consideration two new initiatives to further assist PE's low-income customers. First, PE is proposing the creation of an "Energy Assistance Outreach Team" to increase awareness, education, and participation in energy assistance programs that are available to low-income customers. This team, which will consist of full-time staff, will assist low-income residential customers with learning about and applying for assistance programs that will help with their utility costs. The team will also partner with targeted organizations and strengthen relationships within the community. Second, PE proposes to implement a "50% Discount Program," which would authorize the Company to provide a 50% monthly discount to distribution charges at the primary residence of income-eligible residential customers during the five-month winter heating period (November-March). These programs comply and are consistent with the Maryland General Assembly's recently-enacted legislation in 2022 to promote the adoption of well-constructed limited-income mechanisms to benefit Maryland's eligible limited-income customers. *See* PUA § 4-309.

7. Pursuant to PUA § 4-309(d)(1)(ii), by way of this Application, PE requests the Commission's prior approval for the Commission to consider as part of this base rate case application these two new low-income programs described in the preceding paragraph and more fully in the testimony and exhibits supporting this Application.

8. In addition to the reliability and low-income customer programs discussed above, PE is proposing a rate adjustment to enable the Company to earn its authorized rate of return. Under the provisions of PUA § 4-101, PE is entitled to an operating income yielding, after a deduction for necessary and proper expenses, a reasonable return upon the fair value of its property, which must be adequate to assure confidence in the financial soundness of the utility, to maintain and support its credit, and to enable it to raise the capital necessary for the proper discharge of its duties as a public service company. *Bluefield Water Works v. Public Service Commission*, 262 U.S. 679 (1923).

9. The requested increases are needed for the Company to continue to provide safe and reliable service to its customers and to maintain the financial health of the Company. As described above, PE continues to make significant investments in its infrastructure while experiencing rising operating costs in order to provide the level of service and reliability that customers expect.

10. In the testimony and exhibits supporting this Application, PE provides evidentiary support for an increase in its electric distribution revenue requirement of $48.5 million, which is $47.5 million plus the approximately $1 million for new low-income assistance programs discussed above.[1] This increase is based on a test year for the 12-month period from January 1, 2022 through December 31, 2022, and an overall rate of return on investment of 7.54%, and an overall return on equity ("ROE") of 10.60%. The Company's proposed rate increase results in an increase of $9.50 per month for an average residential customer using 1,000 kWh per month, representing a 9.7% increase in the customer's total bill. For an aggregate of all customer classes, the proposed rate increase results in a 6.4% increase in the customer's total bill.

[1] As discussed in the testimony supporting this Application, however, the $48.5 million increase in distribution revenues will be accompanied by an approximate $4.8 million decrease in the EDIS, resulting in a net change in revenues of $43.8 million.

11. Importantly, even with all of the Company's critical infrastructure investments leading to the requested rate increase, the Company's proposed rates will remain the lowest investor-owned electric utility rates in the State of Maryland. Even after the proposed rate increase, an average residential customer in the PE service territory will pay a distribution rate that is 31% less than the BGE and Pepco's current rates, and 40% less than Delmarva Power & Light Company's current rates. PE's customers will still benefit from having the lowest distribution rates of all investor-owned utilities in Maryland. This will be true even if the Commission approves the Company's requested rate request and reliability surcharge (the EDIS Part II) in full.

12. This Application is supported by the prepared direct testimony and exhibits of:

- Raymond E. Valdes, Director, Rates and Regulatory Affairs at FirstEnergy Service Company;
- Stephanie L. Fall, Manager, Rates and Regulatory Affairs at FirstEnergy Service Company;
- Donald J. McGettigan, Director, Operations at The Potomac Edison Company;
- Weizhong (Bill) Wang, Assistant Treasurer, Treasury at FirstEnergy Service Company;
- Gregory J. Gawlik, Assistant Controller, Tax at FirstEnergy Service Company;
- Susan M. Colflesh, State Regulatory Analyst, Rates and Regulatory Affairs Department – West Virginia/Maryland at FirstEnergy Service Company;
- Bobbi S. Miller, Analyst IV, Rates and Regulatory Affairs at First Energy Service Company;
- Jill A. Soltis, Analyst V, Rates and Regulatory Affairs at FirstEnergy Service Company;
- Heather E. Ward, Analyst, Rates and Regulatory Affairs at FirstEnergy Service Company;
- Tracy M. Ashton, Assistant Controller Corporate at FirstEnergy Corp.;
- Walter S. Larnerd, Manager, Revenue Operations Strategy at FirstEnergy Service Company;
- Dylan W. D'Ascendis, Partner at ScottMadden, Inc.;
- Timothy S. Lyons, Partner at ScottMadden, Inc.;[2]
- John J. Spanos, President at Gannett Fleming Valuation and Rate Consultants, LLC; and
- Mark Warner, Vice President at Gabel Associates, Inc.

[2] Mr. Lyons will be providing two pieces of testimony: one regarding cash working capital, and one regarding the Company's class cost of service ("CCOS") and rate design.

13. This Application will also be supported by voluminous data submissions required by the Commission's April 18, 1983 Secretarial Letter Order, which provides that the supplemental filing requirement is "a possible means to expedite Commission proceedings by providing as much relevant data as possible at the beginning of the proceeding thereby obviating or diminishing the need for subsequent time consuming and costly data requests." This will be provided in a supplemental submission labeled "Supplemental Information" that will be filed with the Commission.

14. PE is also filing with the Commission today: (1) its Cost Allocation Manual ("CAM") for 2021, in accordance with the Code of Maryland Regulations 20.40.02.07B; and (2) the independent audit opinion of Pricewaterhouse Coopers LLP, which was prepared following an examination of the 2021 CAM pursuant to the provisions of PUA § 4-208.

15. In addition to the above information, PE wishes to note that it has performed and includes with this Application all of the required studies in compliance with the Commission's Order No. 89072 issued in PE's last rate case, to wit:

- Updates to its Jurisdictional Cost of Service Study ("JCOSS") and Cost of Service Study ("COSS"), such that all updated studies are current to within one year of the test year in the present application (January 1, 2022 – December 31, 2022)
- A COSS with and without a zero intercept study;
- A COSS that includes a labor allocator to better reflect the functionalization of general and intangible plant;
- Testimony supporting or rejecting the use of the Average Coincident Peak ("ACP") methodology to allocate costs related to subtransmission and FERC Accounts 362 and 368 capacitors based on current system conditions and cost causation; and
- Three years of demand at transmission, subtransmission, primary, and secondary levels, as well as their resulting allocators that are used in the COSS.

16. Finally, as more fully discussed in the Company's testimony, PE hereby advises the Commission that effective January 1, 2022, FirstEnergy and, likewise, PE, adjusted its capitalization rate for Administrative and General ("A&G") overhead costs as a result of a representative labor time study conducted by an independent, third-party entity in response to an

audit report from the Federal Energy Regulatory Commission's ("FERC") Division of Audits and Accounting. The effect of the adjustment to A&G capitalization was to reduce amounts of costs that were capitalized and increase amounts that were charged to operations and maintenance ("O&M"). Also, in response to the FERC audit, FirstEnergy and, likewise, PE reclassified the change in A&G plant and reserve for the amounts capitalized between years 2015 and 2021 to an A&G capitalization regulatory asset. As a result, the Company is proposing to include the A&G capitalization regulatory asset in rate base and to recover this regulatory asset by amortizing the balance removed from each plant account and included in this regulatory asset by applying the Commission-approved depreciation rates applicable to the plant account from which each balance was removed. This will ensure that customer rates are not impacted by this reclassification.

17. In accordance with PUA § 4-203, PE's revised rate schedules are submitted with a proposed effective date of April 22, 2023. The testimony and exhibits filed herewith in support of this Application demonstrate that the proposed rate increases are essential, cost justified, and required to assure continued adequate service and to achieve the minimum rate of return needed to attract capital at reasonable costs.

WHEREFORE, The Potomac Edison Company urges the Commission to find the accompanying revised rate schedules for retail electric distribution service in Maryland to be just and reasonable, and authorize the rates and charges specified therein to become effective.

[*signature page follows*]

Respectfully submitted,

THE POTOMAC EDISON COMPANY

By: ______________________

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March 22, 2023

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

RAYMOND E. VALDES

Concerning: Overview of Application

March 22, 2023

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Raymond E. Valdes, and my business address is 800 Cabin Hill Drive, Greensburg, Pennsylvania 15601.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by FirstEnergy Service Company and my title is Director, Rates and Regulatory Affairs. My time is devoted to tasks performed for The Potomac Edison Company ("PE" or "Company") and Monongahela Power Company ("Mon Power").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I am a graduate of the University of Pittsburgh where I earned a Bachelor of Science in Electrical Engineering. I have over 32 years of experience with FirstEnergy Service Company or its predecessor companies, and have held positions of Engineer, Power Services; Engineer, Rates; Regulatory Specialist; Senior Consultant; Rates Advisor; General Manager, Retail Pricing Services; and my current position of Director, Rates and Regulatory Affairs. My current duties and responsibilities include directing the rates and regulatory activities for PE's Maryland and West Virginia operations and Mon Power's West Virginia operations.

Q. HAVE YOU TESTIFIED IN RATE PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes, I have testified in proceedings before the Maryland Public Service Commission ("Commission"), the Public Service Commission of West Virginia, the Public Utilities

Commission of Ohio, the Pennsylvania Public Utility Commission, and the Virginia State Corporation Commission.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to:

1) Provide an overview of the Company and comparison of the Company's rates regionally and nationally;
2) Summarize the Company's distribution base rate increase;
3) Provide information on the Company's new low-income residential assistance programs to help with the affordability of electric service for the Company's low-income customers;
4) Introduce the other witnesses for the Company in this proceeding who will detail individual aspects of the Company's rate filing for increased revenues sufficient to cover its cost of service and provide an adequate return for its investors; and
5) Address additional items, such as the request for a storm deferral and a proposal for customer refunds.

Q. HAVE YOU PREPARED OR HAD PREPARED UNDER YOUR SUPERVISION EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A. Yes, I have. Exhibits RV-1 through RV-3 provide calculations regarding costs that should not have been included in customer rates from the Company's prior distribution base rate case, Exhibit RV-4 presents the summation of such costs (with interest) that has accumulated between the prior distribution rate case and eventual customer refund, and

Exhibit RV-5 presents a calculation of the credits to refund to customers for the above-mentioned amounts. These exhibits are described in detail in my testimony.

II. OVERVIEW OF THE COMPANY

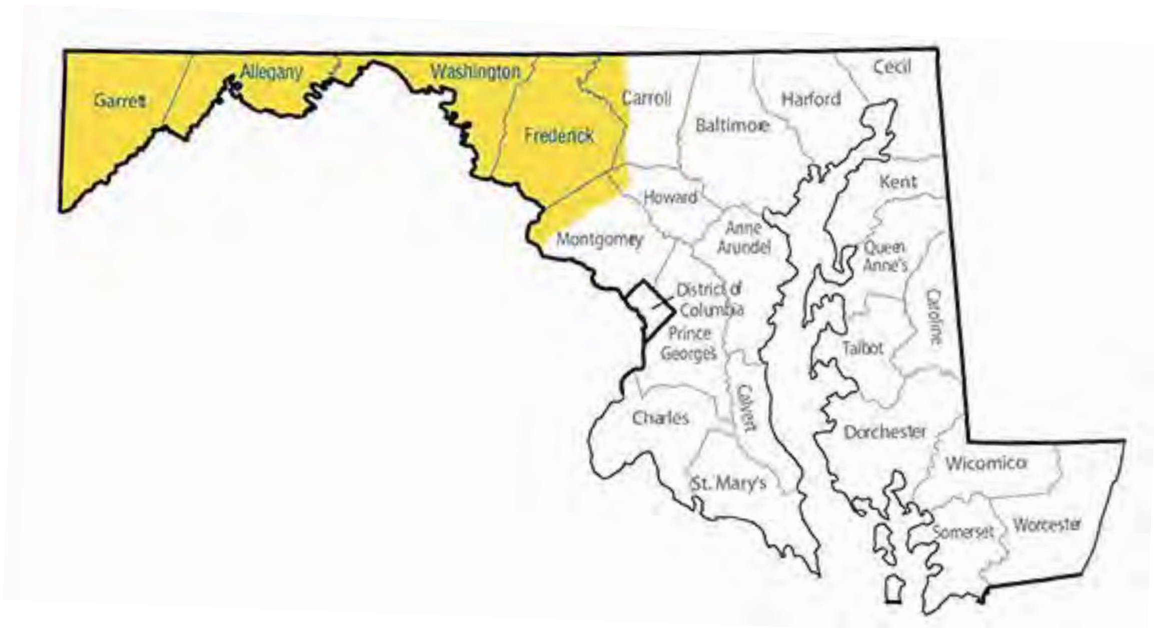
Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY.

A. PE is a Maryland electric distribution utility that is a part of the FirstEnergy Corporation ("FirstEnergy") family of electric utilities. PE is headquartered in Williamsport, Maryland and provides retail electric service to approximately 285,000 customers in Maryland,[1] representing approximately 11% of the electric customers in Maryland. PE's residential customers make up about 88% of the Company's Maryland customer count and account for about 49% of the 6.8 million kilowatt-hours ("kWh") delivered by PE in 2022. Commercial customers are about 11% of PE's Maryland customer base and are about 29% of the kWh delivered, while industrial customers account for about 1% of the customer base and about 22% of the kWh delivered in 2022.[2]

PE's Maryland service territory includes all or parts of Allegany, Carroll, Frederick, Garrett, Howard, Montgomery, and Washington counties and is a combination of suburban, rural, and mountainous terrain and demographics. PE's service territory in Maryland is depicted in yellow below.

[1] PE also provides retail electric service to customers in West Virginia and owns transmission facilities in Maryland, West Virginia, and Virginia.

[2] For purposes of my testimony, residential consists of customers billed on Schedule R, commercial consists of customers billed on Schedules G, C, C-A, the CSH subset of C-A, and PH (less than 600 kW), and industrial consists of customers billed on Schedules PH (600 kW and greater), PP and AGS.



PE's Maryland service territory and reliability is more fully described in the testimony of Company witness McGettigan.

Q. PLEASE DESCRIBE THE EFFORTS OF FIRSTENERGY AND PE WITH REGARD TO DIVERSITY, EQUITY, AND INCLUSION.

A. FirstEnergy has received numerous awards, which include the 2022 Leading Disability Employer Seal by the National Organization on Disability, Forbes' Best Employers for Diversity in 2020, DiversityInc's Top Utilities list in 2019, 2020 and 2021, recognition by the Bloomberg Gender-Equality Index for women's equality in the workplace in 2019, 2020 and 2021, recognition by G.I. Jobs magazine as a Military Friendly employer every year since 2016, and in 2023 was designated as a Top 50 Diversity Employer by Minority Engineer magazine.

Also, FirstEnergy and the Company are committed to providing opportunities to small, women-owned, minority-owned, Historically Underutilized Business Zones ("HUBZone"), veteran-owned, and service-disabled veteran-owned businesses through its supplier diversity program. In 2020, FirstEnergy spent $482 million with diverse suppliers and earned the 2021 Regional Council Member Done Deals award from the Women's Business Enterprise Center-East ("WBEC-East") for the $54.8 million spent with women-owned businesses certified by WBEC-East. Additionally, PE participates in the FirstEnergy's Preferred Supplier Program, which seeks to support minority businesses within the FirstEnergy footprint using a three-pronged approach:

1. Enrollment – Companies identified by FirstEnergy will be given the opportunity to grow their existing relationship and possibly be used as a supplier.
2. Support – Assistance to suppliers enrolled in the program through mentorship and training.
3. Investment – FirstEnergy will invest in minority-owned funds that are willing and able to invest in diverse businesses across our service territory.

PE exceeded its long-term supplier diversity goal of 25% in every year since the last time the Company filed a rate case in 2018, including in 2022 by achieving a supplier diversity spend of 27.87%. PE continues to invest in its supplier diversity programs by, for example, using vendor data reports to identify categories where diverse supplier utilization has been low, and strengthening its supplier diversity recruitment initiatives in those categories.

Moreover, PE is proudly involved in the communities that it serves and the Company's employees take pride in supporting their local communities. The FirstEnergy Foundation and PE have donated nearly $890,000 over the last decade to Maryland and West Virginia United Way agencies and raised almost $174,000 for Maryland and West Virginia-based food banks through Harvest for Hunger, an annual awareness campaign aimed at fighting hunger.

Q. TURNING TO PE'S ENVIRONMENTAL POLICIES, DOES THE COMPANY ENGAGE IN PRACTICES TO ADDRESS CLIMATE CHANGE AND ITS IMPACTS, AND TO FURTHER MARYLAND'S GOALS FOR REDUCING STATEWIDE GREENHOUSE GAS EMISSIONS?

A. Yes. PE supports initiatives and programs that encourage and incent customers to use energy more efficiently and to adopt electric vehicles ("EVs"), and that foster the state's transition to clean energy. PE has been an active participant in EmPOWER Maryland since the program's inception, and the Company continues to offer energy efficiency and conservation programs, which currently are designed to assist customers in reducing their energy consumption. PE is currently nearing the end of its 2021-2023 EmPOWER Maryland program cycle. It is my understanding that as the Company plans for the 2024-2026 cycle, it is looking to propose plans and programs to target reducing greenhouse gas emissions in addition to improving energy efficiency.

To support the state's transition to clean energy, PE also received Commission approval for two energy storage pilot projects. The first project went into service in late 2022 and will be used to study the interaction between EV public charging and battery storage. The second project is projected to be completed by February 2024. Also, to help further expand the adoption of EVs across its service territory, PE is advancing several programs including the offering of residential and multi-family rebates for EV chargers and the installation of public EV chargers. PE also recently filed a proposal for a residential EV-only time-of-use rate plan. The Company is committed to supporting its customers and the State of Maryland in reaching their clean energy goals and to helping power a cleaner, healthier, sustainable future.

Q. DOES PE COMPLY WITH FEDERAL, STATE, AND LOCAL ENVIRONMENTAL REGULATIONS AND LAWS?

A. Yes. It is my understanding that in addition to advancing programs that support energy efficiency in Maryland and investing in programs to develop and promote EVs, PE is in compliance with all applicable federal, state, and local environmental regulations and laws.

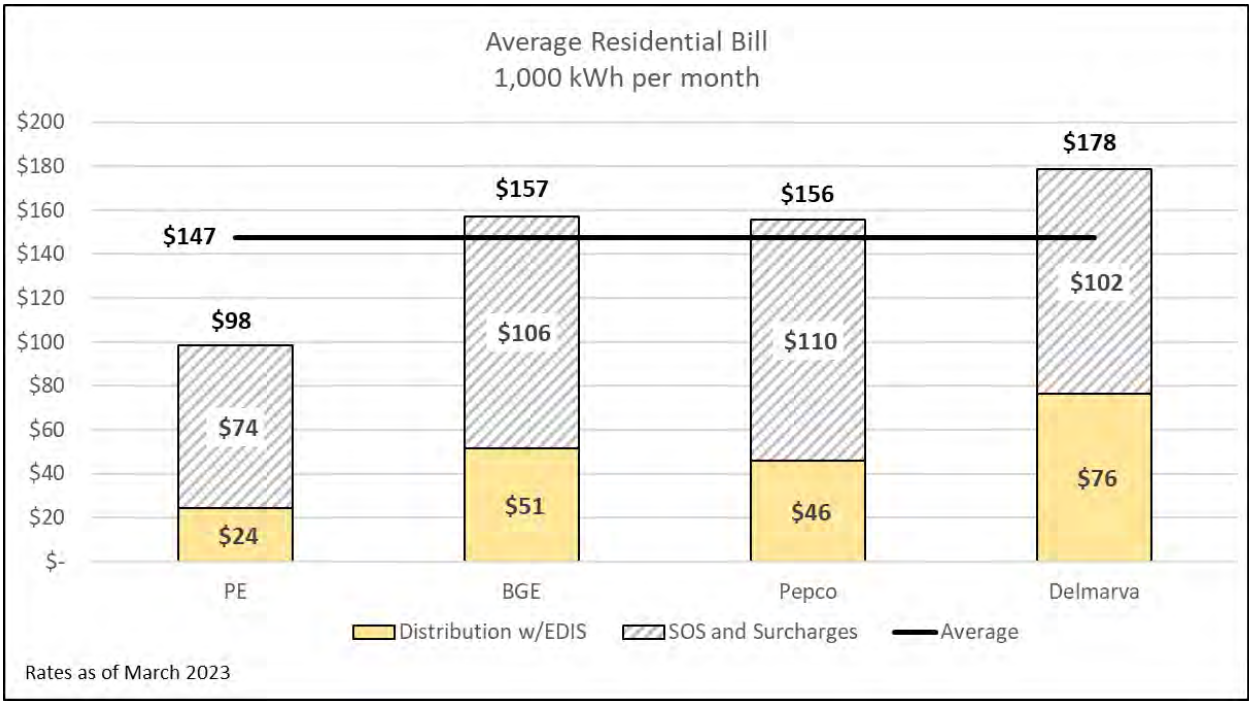
Q. HOW DO PE'S RATES CURRENTLY COMPARE TO MARYLAND AND NATIONAL ELECTRIC RATES?

A. Very favorably. PE's residential electric rates are currently the lowest amongst the investor-owned electric utilities in Maryland and are among the lowest nationally. Chart 1 below depicts a residential electric bill in Maryland as of March 2023 based upon an average usage of 1,000 kWh per month. As shown on the chart, an average PE residential bill for distribution[3] service is less than half of other Maryland investor-owned electric

[3] Distribution rates for PE in this chart include the Electric Distribution Investment Surcharge since that surcharge represents costs that will eventually be rolled into distribution rates.

utilities and, after adding in surcharges[4] and standard offer generation service, is over 35% below the state average.

Chart 1



The Company's electric rates also compare favorably to national electric rates. The Company's total electric rate for an aggregate of all customers in 2022 was approximately 9.9 cents per kWh, which when compared to the most recent data available from the United States Energy Information Administration ("U.S. EIA"),[5] is the lowest from all states east of the Mississippi River and 13th lowest in the nation. With regard to residential customers,

[4] Surcharges exclude generation reconciliation mechanisms (identified as an energy cost adjustment or procurement cost adjustment) and decoupling bill stabilization adjustment mechanisms since those mechanisms alternate between charges and credits throughout the year and, as such, rates effective during March 2023 are not necessarily representative of annual rates. The inclusion in March 2023 rates of these mechanisms would not materially affect the results depicted on the chart.
[5] Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, December 2022.

the previously-mentioned average bill for PE residential customers is currently $98 per month, which translates to 9.8 cents per kWh and was the second lowest in the nation for the U.S. EIA most recent reporting period.[6]

In sum, PE provides safe, reliable, and cost-effective electric service to approximately 285,000 customers throughout its varied and diverse Maryland service territory, which includes large parts of Maryland's rural and mountainous terrain. PE employs hundreds of Marylanders, who contribute their skills to support the Company in its goal to provide its customers and communities with consistent, safe, and reliable electric service. The Company's concerted efforts to increase supplier diversity have allowed PE consistently to exceed its diverse supplier spend goal, and PE and its employees contribute to the Maryland economy through corporate philanthropy initiatives.

III. COMPANY'S BASE RATE INCREASE

Q. PLEASE EXPLAIN THE BACKGROUND FOR THE COMPANY'S DISTRIBUTION BASE RATE FILING.

A. PE's prior distribution base rate case was filed on August 24, 2018 in Case No. 9490 and ended with Commission Order No. 89072 (the "Order") issued on March 22, 2019 that authorized an increase in distribution rates effective March 23, 2019. That Order also issued interlocking directives with respect to the duration of the Electric Distribution Investment Surcharge ("EDIS") program and its relationship with the Company's next base

[6] Only North Dakota was lower at 9.62 cents per kWh, per Table 5.6.A as of December 2022.

rate case filing. Specifically, the Commission directed the Company to submit a base rate case application that aligns with the end of the initial four-year period of EDIS (end of 2022 or early 2023).[7] In accordance with the Order, the Company is submitting its distribution base rate filing application in early 2023 (i.e., four years after the issuance of the Order) to: (1) roll into rate base the EDIS capital costs for 2019-2022 so that those costs will no longer be recovered through a surcharge upon conclusion of this proceeding; and (2) request current rate relief to address a new revenue deficiency. As a result, this distribution base rate proceeding provides the Commission an opportunity to address the roll-in of EDIS costs into distribution rates, provide revenues sufficient to cover the Company's cost of service, and determine a reasonable rate of return that will allow the Company to attract the necessary capital resources to continue to provide our customers with safe and reliable distribution service.

Q. WHAT IS THE TEST PERIOD UTILIZED IN THE COMPANY'S REQUEST FOR RATE RELIEF?

A. The Company's filing is a traditional base rate filing utilizing a historical test year (meaning the Company's filing is not a multi-year rate filing). The test year is 12 months ended December 2022, with rate base calculated on a 13-month average from December 2021 through December 2022.

Q. DOES THE HISTORICAL TEST YEAR INCLUDE ANY FORECASTED AMOUNTS?

[7] Order at 12.

A. No. Although past practice has permitted the filing by utilities of a partially forecasted test year, in cases filed that way the forecasted test year amounts must ultimately be replaced in the record with actual amounts to ensure Commission determination is based upon a historical test year utilizing actual cost data. The practical effect of having to submit testimony regarding, and to take and provide discovery on, two sets of numbers is that all the parties, including the applicant, Staff, and Office of People's Counsel ("OPC"), have to do a large amount of duplicative work in such cases. Here, however, in an effort to help ease the administrative burden associated with evaluation of two different sets of Company filing data (i.e., an initial set with a partially forecasted historical test year followed a couple months later with a second set with a historical test year based upon actual cost data), the Company has endeavored to submit its initial distribution base rate application based solely on actual cost data from a historical test year of 2022. This should significantly ease the review and evaluation process for all parties with respect to the Company's distribution base rate application. The Company has, though, included some post-test year adjustments as described by Company witness Soltis.

Q. DOES THE COMPANY ANTICIPATE ANY UPDATES TO ITS FILING?

A. Yes. Due to the desire of the Company to initially file its distribution base rate application based upon actual cost data from a historical test year and due to the limited time between the end of 2022 through the date of this filing, the depreciation study sponsored by Company witness Spanos is based upon plant and reserve balance data as of June 30, 2022. However, the Company has recently provided Mr. Spanos with updated plant and reserve balance data as of December 31, 2022, to eventually synchronize the depreciation study with the end of the historical test year. Upon completion of the depreciation study with data as of December 31, 2022, the Company will file an update to its distribution base rate case to reflect the depreciation rate results of the updated depreciation study as well as any other changes or corrections that may have occurred subsequent to this initial filing.

Q. WHAT IS THE COMPANY'S REQUESTED CAPITAL STRUCTURE AND RETURN IN ITS REQUEST FOR RATE RELIEF?

A. As more fully described and supported by Company witness Wang, PE's requested capital structure is the Company's actual capital structure on December 31, 2022, with ratios of 53.53% for common equity and 46.47% for long-term debt. The Company's embedded long-term debt cost rate is 4.018% and, as described and supported by Company witness D'Ascendis, the requested return on equity is 10.60%. The resultant rate of return is 7.54%.

Q. PLEASE SUMMARIZE THE COMPANY'S OVERALL REQUEST IN THIS CASE.

A. The Company's request is detailed in the testimony of other witnesses but, generally, the Company is requesting a $47.5 million increase[8] in base distribution revenues based on an overall rate of return of 7.54%. As the Company is experiencing a revenue deficiency, it is necessary that it makes this request for rate relief in conjunction with the request to roll into rate base (and subsequently decrease from surcharge recovery) EDIS capital costs incurred during 2019-2022.

[8] The requested increase is also displayed on the income statement sponsored by Company witness Soltis in Exhibit JAS-1 (column 6).

Q. IS THE COMPANY PROPOSING ANY NEW INITIATIVES TO HELP LOW INCOME CUSTOMERS WITH THE AFFORDABILITY OF THEIR ELECTRIC BILL?

A. Yes. To assist low-income customers with paying their electric bill and to help increase participation in available low-income assistance programs, PE is proposing a new "Energy Assistance Outreach Team" and a "50% Discount Program." The "Energy Assistance Outreach Team" is designed to increase awareness, education and participation in energy assistance programs that are available to low-income residential customers; whereas the "50% Discount Program" will provide a 50% monthly discount to distribution charges to income-eligible residential customers during the winter heating period.[9] These two programs are discussed in greater detail in the direct testimony of Company witness Larnerd.

Q. WHAT IS THE COST OF THE TWO PROGRAMS TO ASSIST LOW-INCOME CUSTOMERS AND HOW WILL THE COST BE COLLECTED?

A. The total estimated annual cost for the two new low-income assistance programs is $1,042,433. Since the programs are solely available to residential customers, cost collection is proposed to be collected through the residential distribution kWh rate of Schedule R. Dividing the $1,042,433 by the 2022 residential weather-normalized distribution kWh and grossing up the result for Maryland gross receipts tax and the Commission assessment factor equates to a rate increment of $0.00032 per kWh. Put

[9] The winter heating period is the five-month period of November through March.

another way, the proposed rate increment to assist low-income residential customers is only 32 cents per month for an average residential customer using 1,000 kWh per month. This small impact on residential customer bills will help the affordability of electric service for the Company's low-income customers.

Q. WHAT IS THE TOTAL OF THE COMPANY'S REQUESTED RATE RELIEF THAT INCLUDES THE NEW LOW INCOME ASSISTANCE PROGRAMS?

A. The Company's total base rate request is an increase of $48.5 million, which is the $47.5 million previously discussed plus the approximately $1 million for new low-income assistance programs. The Company's requested increase, however, reflects the movement of about $4.8 million of EDIS revenues from the surcharge to distribution rates. In other words, the $48.5 million increase in distribution revenues will be accompanied by an approximate $4.8 million decrease in the EDIS, resulting in a net change in revenues of $43.8 million.

Q. WHAT ARE SOME OF THE CONTRIBUTING FACTORS FOR THE NEED FOR THE REQUESTED RATE RELIEF?

A. In general, the Company is seeking an increase in rates because its revenues are not sufficient to cover the cost of service, including a reasonable return to investors. There are several items that contribute to the requested rate increase. First – and as further described below – it represents an increase in rate base supported by incremental capital expenditures to provide benefit to our customers. Also, increases in operation and maintenance ("O&M") expenses are primarily attributable to costs associated with vegetation management and changes in FirstEnergy's capitalization policy. In the Company's prior distribution rate case, PE requested recovery through the EDIS for the costs to transition its vegetation management program from a five-year vegetation management clearing cycle to a four-year clearing cycle, which is also consistent with the clearing cycle for other Maryland electric utilities. Although incremental cost recovery was not approved by the Commission through the EDIS, the Company remained concerned of the impact of tree-caused outages to electric service reliability and subsequent impact to customers. Therefore, the Company proceeded with its transition from a five-year vegetation management clearing cycle to a four-year clearing cycle to help improve reliability performance for its customers. Also, the cost increase in this filing that is associated with vegetation management is inherent in the regulatory lag process where costs are initially incurred and then subsequently recovered through future base rate cases.

Additionally, as more fully discussed by Company witness Ashton, effective January 1, 2022, FirstEnergy and, likewise, PE adjusted its capitalization rate for Administrative and General ("A&G") overhead costs as a result of a representative labor time study conducted by an independent, third-party entity in response to an audit report from the Federal Energy Regulatory Commission's ("FERC") Division of Audits and Accounting. The effect of the adjustment to A&G capitalization was to reduce amounts that were capitalized and increase amounts that were charged to O&M. For example, if approximately 57% of A&G costs were previously capitalized, then the remaining 43% of A&G costs were charged to O&M. A reduction of the capitalization percentage to 28% would then translate to 72% of A&G costs being charged to O&M. Also, in response to the FERC audit, FirstEnergy and, likewise, PE reclassified the effect of the change in A&G

overhead percentages on plant and reserve for the amounts capitalized between years 2015 and 2021 to an A&G capitalization regulatory asset. The Company is proposing to include the A&G capitalization regulatory asset in rate base and to recover this regulatory asset by amortizing the balance removed from each plant account and included in this regulatory asset by applying the Commission-approved depreciation rates applicable to the plant account from which each balance was removed. This ensures that customer rates are not impacted by this reclassification. Because the reclassification has no impact on rate base or recovery, items impacted continue to be shown in the appropriately charged plant accounts within this filing.

Furthermore, during 2021, an additional change to vegetation management capitalization occurred whereby the capitalization percentage for vegetation management was lowered with a corresponding increase in the percentage charged to O&M. Since O&M has a greater effect on customer rates than capital, the effect of the reduction in capitalization percentages and subsequent increases in O&M percentages tends to increase customer rates.

Q. DID CHANGES IN CAPITAL PLACED IN SERVICE BETWEEN RATE CASES ALSO HAVE AN EFFECT ON THE COMPANY'S REQUEST FOR RATE RELIEF?

A. Yes. A portion of the increase in capital placed in service, which subsequently increases rate base, is due to the rolling into rate base of EDIS capital costs for 2019-2022. There are also other capital projects that contribute to the increase in capital placed in service, such as those that are used to bolster and/or improve reliability to the benefit of customers, as more fully described by Company witness McGettigan.

Q. BASED ON THE COMPANY'S REQUEST FOR RATE RELIEF, WHAT WILL BE THE IMPACT TO CUSTOMERS?

A. Table 1 below shows a summary of the impact per rate schedule of the Company's request for rate relief, which includes the proposed low-income assistance programs and reduction in the current EDIS rate.

Table 1

Rate Schedule	Distribution Revenue[1] Current	Distribution Revenue[1] Proposed	Low-Income Programs[2]	EDIS Reduction	Change	Total Bill % Change[3]
(a)	*(b)*	*(c)*	*(d)*	*(e)*	*(f) = (c)+(d)+(e)-(b)*	*(g)*
R (residential)	$ 83,434,046	$ 116,805,235	$ 1,066,726	$ (2,885,189)	$ 31,552,725	9.5%
G, C	24,649,053	31,710,614	-	(789,248)	6,272,313	5.7%
Hag/Fred	22,208	29,012		(1,239)	5,565	6.4%
C-A, CSH	435,542	569,506	-	(28,456)	105,508	3.7%
PH, AGS	19,362,724	25,006,595	-	(1,043,863)	4,600,008	2.7%
PP	1,374,959	1,776,695	-	(14,192)	387,545	0.6%
Street Lighting	4,969,621	5,843,144	-	(25,029)	848,494	13.6%
Total	$ 134,248,154	$ 181,740,802	$ 1,066,726	$ (4,787,214)	$ 43,772,160	6.4%

[1] Distribution includes tax surcharges for the Franchise Tax and the Montgomery County Fuel Energy Local Tax
[2] $1,042,433 grossed-up for Maryland gross receipts tax and the Commission assessment factor
[3] Based upon rates as of March 2023

The proposed rate increase results in an increase of $9.50 per month for a residential customer using 1,000 kWh per month, representing a 9.7% increase in the customer's total bill.[10] For an aggregate of all customer classes, the proposed rate increase results in a 6.4% increase in the customer's total bill.

Q. ARE THERE ANY ADDITIONAL ASPECTS OF THE COMPANY'S DISTRIBUTION RATE APPLICATION?

A. Yes. In addition to the Company's request for rate relief, PE is also seeking the continuation of the EDIS program in a Phase II. The proposed EDIS Phase II will fund three incremental reliability programs for underground cable replacement, substation reclosers, and resiliency, as explained in further detail in the direct testimony of Company witness McGettigan. Notwithstanding the Company's positive reliability and service performance and the significant investments the Company has made in those areas, PE understands that our customers and this Commission expect our continuous improvement. These programs will provide real and meaningful benefits to our customers and help increase our reliability performance to ensure that the Company continues to meet and exceed this Commission's standards and expectations, and are not related to the base rate increase request. The surcharge rate change associated with EDIS Phase II will not occur until January 1, 2024, to coincide with commencement of the EDIS Phase II, and is addressed in further detail by Company witness Fall.

Q. IF THE COMPANY'S REQUEST IS APPROVED, HOW WILL PE'S RATES COMPARE TO THE RATES OF MARYLAND'S OTHER ELECTRIC UTILITIES?

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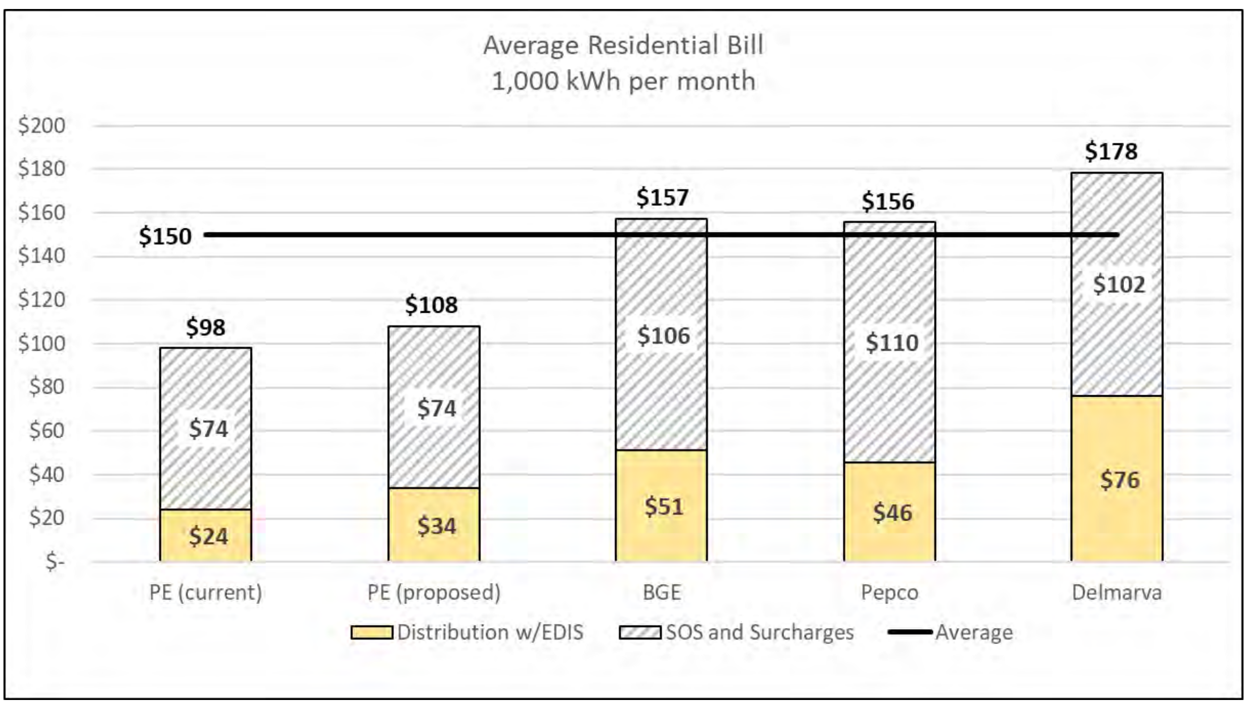
[10] The percentage increase of 9.7% differs slightly from the class average 9.5% provided in Table 1 since the actual average monthly kWh usage is slightly higher than 1,000 kWh per month.

A. The Company's proposed rates will still compare favorably to those of Maryland's other investor-owned electric utilities in that they will continue to remain the lowest in the State of Maryland. Chart 2 is a replication of my previous Chart 1 that depicts a residential electric bill based upon an average usage of 1,000 kWh per month. However, in Chart 2, I have added the effect of the Company's proposed rate increase which, even after the increase, results in a monthly bill that is less than the other Maryland investor-owned electric utilities on a distribution-only basis and a total bill basis. In sum, the Company's rates will still be the lowest of any of the investor-owned electric utilities in the state and the new low-income assistance programs will further assist those with limited incomes.

Chart 2



Additionally, even after the proposed rate increase, the Company's electric rates will continue to compare favorably to national electric rates. The new total electric rate of approximately 10.6 cents per kWh for an aggregate of all customers will still be one of the lowest of all states in the nation and lower than all states east of the Mississippi River (with the exception of West Virginia and North Carolina) when compared to the most recent data available from the United States Energy Information Administration ("U.S. EIA").[11] The new average PE residential customer rate of 10.8 cents per kWh will be 7th lowest in the nation and lower than all states east of the Mississippi River.[12]

Q. HOW WILL THE PROPOSED RATE INCREASE BRING VALUE TO PE'S CUSTOMERS?

A. PE must attract capital at cost-effective rates to remain a financially strong company that can continue to invest in its distribution system. The Company is under-earning its authorized rate of return, as well as earning less than the Commission-approved returns for the state's other electric distribution utilities. By authorizing the Company to earn a fair rate of return, the Commission will allow the Company to maintain the stability and profitability needed to attract investors and capital at cost-effective rates. As a result, the Company will then be well-positioned to continue its capital expenditures program, which will allow us to continue to meet our customers' and this Commission's expectations of the safe and reliable service for which we are known.

IV. OVERVIEW OF THE APPLICATION

Q. PLEASE PROVIDE AN OVERVIEW OF THE APPLICATION.

[11] Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, December 2022.
[12] Only North Dakota was lower at 9.62 cents per kWh, per Table 5.6.A as of December 2022.

A. PE's request for rate relief in this proceeding consists of the Company's Application for rate relief, and the direct testimonies and supporting documentation and exhibits of witnesses testifying on behalf of the Company.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WITNESSES TESTIFYING ON BEHALF OF THE COMPANY AND THE SUBJECT MATTERS THEY WILL DISCUSS.

A. The following witnesses are employed by the Company or affiliates of the Company and have submitted direct testimony and supporting exhibits in this proceeding:

1) Jill A. Soltis, Analyst in the Rates and Regulatory Affairs Department, provides the Company's income statement and rate base, and describes certain ratemaking adjustments.

2) Susan M. Colflesh, Analyst in the Rates and Regulatory Affairs Department, provides the jurisdictional separation study and describes certain ratemaking adjustments.

3) Heather E. Ward, Analyst in the Rates and Regulatory Affairs Department, describes certain ratemaking adjustments.

4) Tracy M. Ashton, Assistant Controller in Corporate Finance, proposes a new pension and other post-employment benefits ("OPEB") expense normalization mechanism ("PON Mechanism"), addresses accounting items and allocations to PE, describes proposed customer refunds, and describes certain ratemaking adjustments.

5) Gregory J. Gawlik, Assistant Controller in the Tax Department, supports state

and federal income tax information used by PE and discusses significant tax law changes.

6) Weizhong (Bill) Wang, Assistant Treasurer in the Treasury Department, describes and supports PE's capital structure, embedded cost of long-term debt, and overall weighted average cost of capital.

7) Stephanie L. Fall, Manager in the Rates and Regulatory Affairs Department, supports the Company's tariff revisions and the rate-related aspects of EDIS Phase II.

8) Bobbi S. Miller, Analyst in the Rates and Regulatory Affairs Department, describes and supports updated studies used by the class cost of service study.

9) Donald J. McGettigan, Director of Operations at PE, provides supporting information regarding electric distribution operations, the Company's reliability performance, and describe the proposed incremental infrastructure improvements in EDIS Phase II.

10) Walter S. Larnerd, Manager, Revenue Operations Strategy in the Revenue Operations Department, addresses two proposed new low-income assistance initiatives for residential customers.

In addition, the following expert consultants are testifying on behalf of the Company and provide supporting documentation and exhibits:

1) Timothy S. Lyons, Partner at ScottMadden, Inc., sponsors and supports the lead lag study, the class cost of service study, and the distribution rate design.

2) Dylan W. D'Ascendis, Partner at ScottMadden, Inc., sponsors and supports the

proposed rate of return on common equity for the Company's Maryland jurisdictional rate base, and calculates the credit-adjusted risk-free rate for PE.

3) John J. Spanos, President at Gannett Fleming Valuation and Rate Consultants, LLC, sponsors and supports the depreciation study and proposed updates to the depreciation accrual rates.

4) Mark Warner, Vice President at Gabel Associates, Inc., presents the results of the benefit-cost analysis performed regarding the suite of electric vehicle charging program offerings developed and implemented by PE.

V. ADDITIONAL ITEMS

Q. ARE THERE ANY ADDITIONAL ITEMS TO ADDRESS REGARDING THIS FILING?

A. Yes, there are two additional items. One is a request for a storm deferral mechanism and the second deals with a customer refund proposal.

Storm Deferral Mechanism

Q. PLEASE ADDRESS THE STORM DEFERRAL MECHANISM.

A. Storm expense can be a volatile category of O&M expense that is unpredictable and outside the control of a utility. No amount of good utility management can eliminate the potential for significant storms that occur in a utility's service territory that can cause considerable damage to utility facilities and infrastructure. As such, the Company proposes to institute deferral accounting for storm expense to periodically compare actual storm O&M expense to the amount currently collected in rates (referred to hereafter as "Storm Deferral Mechanism"). Deferral accounting will be calculated on a monthly basis, with any over-collection recorded as a regulatory liability and any under-collection recorded as a regulatory asset. This will ensure that customers will ultimately pay only the actual incurred level of storm expense – no more and no less. To be clear, this is <u>not</u> a request for a surcharge. The Company acknowledges that the Commission would retain full authority to determine the prudency of any future storm expenses. This is simply a request for authorization to establish an accounting mechanism to record over-collected amounts as a regulatory liability and under-collected amounts as a regulatory asset. Distribution rates would not be adjusted until the Company's subsequent base rate case, at which time the cumulative regulatory liability or regulatory asset would be presented to the Commission for determination of disposition in customer rates.

Q. HOW WOULD THE STORM DEFERRAL MECHANISM BE ESTABLISHED AND OPERATE?

A. The first step is to establish a baseline by which actual storm O&M expenses will be compared. Adjustment No. 5 sponsored by Company witness Ward sets forth a level of storm O&M expense that is equivalent to a five-year annual average, which effectively normalizes within distribution rates a level of annual storm collection expense. Effective with the establishment of new distribution rates in this proceeding, on a monthly basis the actual level of storm O&M expense will be compared against the baseline level with an accounting entry made to record amounts that are in excess or less than the baseline. The cumulative amount, represented as a regulatory liability if it is an over-collection or a regulatory asset if it is an under-collection, will be presented by the Company in the subsequent distribution base rate proceeding as a request for a rate adjustment to return to customers (in the case of a cumulative over-collection) or collect from customers (in the case of a cumulative under-collection). In that proceeding, all intervening parties will be afforded the opportunity to closely examine and evaluate the request and storm-related expenses.

Q. PLEASE PROVIDE AN EXAMPLE OF THE STORM DEFERRAL MECHANISM.

A. Shown below in Table 2 is an example of how the Storm Deferral Mechanism would have worked if it had been approved in the Company's last distribution base rate proceeding

Table 2

Baseline	$3,387,162	Proposed storm O&M from last base rate case	
		Under/(Over)-Collection	
2019 Storm O&M	$5,643,850	$2,256,688	*2019 minus Baseline*
2020 Storm O&M	$1,072,305	($2,314,857)	*2020 minus Baseline*
2021 Storm O&M	$1,431,460	($1,955,702)	*2021 minus Baseline*
2022 Storm O&M	$2,616,818	($770,344)	*2022 minus Baseline*
Total (Over)-Collection =		($2,784,215)	

In the above example, a cumulative over-collected amount (i.e., a regulatory liability) of $2,784,215 would have been presented to the Commission in this proceeding as a reduction to customer rates.

Q. DID THE COMMISSION APPROVE THE COMPANY'S REQUEST FOR A STORM DEFERRAL MECHANISM IN THE PRIOR BASE RATE CASE?

A. No. Although Commission Staff did not object to the Storm Deferral Mechanism based on certain conditions, the Commission agreed with the argument of OPC that the Company's proposal was not necessary or appropriate since the use of a five-year average to normalize storm damage expense allegedly provides an opportunity to recover storm damage expense.[13] However, in that proceeding, the Commission did not approve either the five-year average or the Storm Deferral Mechanism. Further, the use of a five-year average is not a means to recover prior storm damage expense. It is used solely as a means to normalize and levelize storm damage expense to a baseline value.

Further, criteria typically used to establish deferral accounting are that the expense is: (1) outside the control of a utility; (2) unpredictable and volatile; and (3) substantial and recurring. Storm-related expenses are certainly outside the control of a utility since the Company has no control over the intensity and duration of potentially significant storms that may affect its service territory. The above Table 2 demonstrates that the storm expenses are indeed unpredictable and volatile since actual storm expenses over the last four years have varied from 23% to as much as 68% from the baseline. In the past ten years, actual storm expenses have varied as much as 227%. Finally, storm damage expense is recurring each year, and the incurrence of millions of dollars in storm damage expense

[13] The Commission did note that, "…the Commission declines to adopt Potomac Edison's proposal for a storm fund at this time." Order at 16. [emphasis added]

is substantial for a utility the size of PE and can potentially be crippling depending upon the size and intensity of future storms.

Q. WHAT WERE THE CONDITIONS FOR A STORM DEFERRAL MECHANISM PUT FORTH BY COMMISSION STAFF IN CASE NO. 9490?

A. Staff believed a Storm Deferral Mechanism would be reasonable with the following conditions: (1) the regulatory asset and regulatory liability balance earn a return based on the Company's most recent authorized rate of return; and (2) the Company file an annual reconciliation with the Commission for the storm-related regulatory asset or liability.[14] The Company is agreeable to both conditions for the establishment of a Storm Deferral Mechanism.

<u>Customer Refunds</u>

Q. PLEASE ADDRESS THE CUSTOMER REFUNDS PROPOSED IN THIS PROCEEDING.

A. FirstEnergy took swift and deliberate action following the investigation of Ohio HB6 activities to report certain costs that may have been improperly classified, misallocated, or lacked proper supporting documentation.[15] To that end, my department received information coordinated through the Controllers Department that identified the costs that were improperly classified, misallocated, or lacked proper supporting documentation, at

[14] Direct Testimony of Yulia Poberesky, pg 11, filed November 20, 2018 in Case No. 9490.
[15] Please see Case No. 9667 for filings and information provided in response to OPC's petition to investigate the relationship of FirstEnergy with PE, as well as the definition of Ohio HB6 activities.

which time my department performed calculations to determine amounts that were reflected in PE Maryland distribution rates. Those calculations first determined the time period by which such costs were reflected in the test year[16] from the last distribution base rate case and then applied allocations from the last base rate case to achieve a PE Maryland distribution jurisdictional amount. Upon calculation of the associated revenue requirement, PE then took proactive action to create a regulatory liability (i.e., future refund to customers) to ensure customers would be refunded such amounts with interest. The workpapers for this calculation are attached to my testimony as Exhibit RV-1 and show that $37,588 was reflected in distribution rates for amounts that were improperly classified, misallocated, or lacked proper supporting documentation.

Q. WERE ANY ADDITIONAL HISTORICAL REVIEWS DONE UNRELATED TO THE REVIEW DISCUSSED IN CASE NO. 9667?

A. Yes. As also described by Company witness Ashton, FirstEnergy performed additional reviews of certain non-operating or non-recoverable costs, including costs associated with advertising, sponsorships, competitive services, and lobbying, and identified certain costs that were recorded to utility operating accounts that were also included in customer rates. The Controllers Department identified the costs allocated to PE, and my department performed a PE Maryland-specific analysis to determine the time period by which such costs were reflected in the test year from the last distribution base rate case and then applied

[16] The test year in the Company's last distribution base rate case was the 12-month period of July 2017 through June 2018. Therefore, any O&M expenses that occurred prior to July 2017 or after June 2018 would not have been reflected in customer rates. Capital costs that were incurred after June 2018 would also not have been reflected in customer rates.

allocations from the last base rate case to achieve a PE Maryland distribution jurisdictional amount. The workpapers for this calculation are attached to my testimony as Exhibits RV-2 and RV-3 and are separated into the categories of Sponsorship/Advertising and Miscellaneous,[17] respectively. The Sponsorship/Advertising category has identified \$195,939 included in distribution rates, whereas the Miscellaneous category has identified \$68,421. A summary of the amounts included in PE Maryland distribution rates is shown below in Table 3.

Table 3

Case No. 9667	\$37,588
Sponsorship/Advertising	\$195,939
Miscellaneous	\$68,421
Total =	\$301,948

Q. BASED UPON THE NUMBERS PROVIDED IN TABLE 3, HOW WAS THE CUSTOMER REFUND DETERMINED?

A. Since the amounts above in Table 3 were reflected in the test year from the last distribution base rate case, as each year passes by, the amounts are incremented annually until new distribution rates are established in this new rate case. There is a timespan of approximately 4 years and 7 months (i.e., approximately 4.6 years) from the date current distribution rates were established on March 23, 2019, through the October 19, 2023 date by which new distribution rates are presumed to be effective from this proceeding. As a result, the

[17] As indicated in Exhibit RV-3, the Miscellaneous category includes amounts related to FE Foundation, FE Products, IT for FE Products, trade association dues, lobbying and vendors.

$301,948 total in Table 3 needs to be multiplied by approximately 4.6 years to determine the total amount in the regulatory liability that will accumulate during that timespan.

Q. IS INTEREST APPLIED FOR THE PERIOD BETWEEN BASE RATE CASES?

A. Yes. The Company applied compounded interest to the regulatory liability at the Company's currently authorized rate of return, which is 7.15%. Further, compounded interest will continue to apply upon conclusion of this base rate case until the amount in the regulatory liability is refunded to customers.

Q. WHAT IS THE TOTAL AMOUNT TO BE REFUNDED TO CUSTOMERS?

A. Once the timespan since the test year and interest is applied, the total refunds to customers equal $1,668,447 – of which $207,363 (12%) represents the amount discussed in Case No. 9667, $1,083,418 (65%) represents sponsorships and advertisement, and $377,666 (23%) represents miscellaneous (as described earlier in my testimony). Detailed calculations supporting the $1,668,447 are contained in Exhibit RV-4 to my testimony.

Q. HOW DOES THE COMPANY PROPOSE TO REFUND THIS AMOUNT TO CUSTOMERS?

A. Like the one-time refunds the Company provided to customers as a result of the Tax Cut and Jobs Act of 2017, the Company proposes to issue a one-time fixed bill credit to customers to discharge the regulatory liability. Specifically, within 30 days of a final order in this proceeding, the Company will file with the Commission the credits that are to be rendered to each customer class. The $1,668,447 regulatory liability will be allocated to rate schedules on the basis of distribution revenue from the Company's last base rate case. The format of the filing and calculation of the credits will be substantially similar to the example provided in Exhibit RV-5. Since such a filing would be made in November 2023, the Company will be requesting Commission approval prior to the end of the year so that refunds can be provided to customers during the month of January 2024. Additionally, following the distribution of the one-time refunds, the Company will submit an informational filing to the Commission that reports the actual refunds distributed to customers not more than 30 days after completion of the distribution of refunds.

The Company wanted to provide the refunds to customers as soon as practical upon conclusion of the base rate case, which is January 2024, and did not want to extend the distribution of customer refunds over an extended period, which is why the refunds are provided over a one-month period instead of an annual or multi-year period. Also, to ensure the full amount of refunds are provided to customers, the refund was designed as a fixed credit per rate schedule[18] since the use of a kWh credit can unfortunately result in a high degree of variability due in large part to unpredictable changes in weather temperature during the winter; whereas the number of customers can be forecasted with a much greater degree of accuracy.

VI. <u>CONCLUSION</u>

Q. PLEASE SUMMARIZE THE COMPANY'S DISTRIBUTION BASE RATE FILING.

[18] Customer credits will be a fixed dollar amount per rate schedule, with the exception of streetlighting customers (which will have a per kWh credit due to their fixed kWh consumption per month) and Schedule PP customers (which due to their unique size will have individual credits for each of the ten customers on that rate schedule).

A. The Company's total rate request is an increase of $48.5 million in distribution revenues accompanied by an approximate $4.8 million decrease in the EDIS, resulting in a net change in revenues of $43.8 million. PE seeks an increase in distribution rates to recover the costs of the Company's ongoing efforts to provide safe and reliable service to its customers. PE's request also includes the rolling into rate base of EDIS capital incurred through 2022; proposing a Phase II of EDIS to continue proactive investments in system reliability and resiliency; recovery of costs for existing deferrals; a proposal for deferrals association with storm and pension/OPEB recovery; approval to include the A&G capitalization regulatory asset in rate base; and two new initiatives to provide further assistance to the Company's low-income residential customers. Even with the proposed rate increase, the Company's rates will still be the lowest of any of the investor-owned electric utilities in the State of Maryland. The Company requests the Commission to approve its base rate application and to find that the revised rates for retail electric service in Maryland result in just and reasonable rates.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

THE POTOMAC EDISON COMPANY - MARYLAND
Summary Case No. 9667

	Prior to Nov 1, 2021	Effective[1] Nov 1, 2021
	MD	MD
Vendor 1		
O&M Annual Rev Req	$ -	$ -
Capital Annual Rev Req	$ 1,238	$ 1,162
	$ 1,238	$ 1,162
Vendor 2		
O&M Annual Rev Req	$ 27,048	$ 27,048
Capital Annual Rev Req	$ 796	$ 749
	$ 27,844	$ 27,797
Vendor 3		
O&M Annual Rev Req	$ 6,442	$ 6,442
Capital Annual Rev Req	$ 2,063	$ 1,945
	$ 8,506	$ 8,387

	MD	MD
Total		
O&M Annual Rev Req	$ 33,490	$ 33,490
Capital Annual Rev Req	$ 4,098	$ 3,856
	$ 37,588	$ 37,346

[1]New depreciation rates were effective November 1, 2021 in accordance with Commission Order No. 89971 dated October 26, 2021 in Case No. 9490 Phase II, which subsequently lowered the capital revenue

THE POTOMAC EDISON COMPANY - MARYLAND
Case No. 9667
O&M Recorded to Account 923

	Vendor 1 PE10	Vendor 2 PE10	Vendor 3 PE10
2017 Jul	$ -	$ 3,696.84	$ -
2017 Aug	$ -	$ 3,696.84	$ 6,538.30
2017 Sep	$ -	$ 3,696.84	$ -
2017 Oct	$ -	$ 3,696.84	$ -
2017 Nov	$ -	$ 3,696.84	$ -
2017 Dec	$ -	$ 14,291.84	$ 6,538.30
2018 Jan	$ -	$ 3,289.00	$ -
2018 Feb	$ -	$ 3,767.40	$ -
2018 Mar	$ -	$ 3,767.40	$ -
2018 Apr	$ -	$ 3,767.40	$ -
2018 May	$ -	$ 3,767.40	$ -
2018 Jun	$ -	$ 3,767.40	$ -
Total PE =	$ -	$ 54,902.04	$ 13,076.60

Maryland	Vendor 1	Vendor 2	Vendor 3
MD rate case test year O&M =	$ -	$ 54,902.04	$ 13,076.60
PE-MD Allocator[1] =	58.116%	58.116%	58.116%
PE-MD rate case test year O&M =	$ -	$ 31,906.87	$ 7,599.60
PE-MD Distribution Allocator[2] =	82.065%	82.065%	82.065%
PE-MD Distribution rate case test year O&M =	$ -	$ 26,184.37	$ 6,236.61
Gross-Up with GRT & PSC Assessment Fee =	$ -	$ 26,771.66	$ 6,376.49
Gross-Up with GRT, PSC Fee & Uncollectibles =	$ -	$ 27,048.09	$ 6,442.33

[1]PE-MD GP01 A&G O&M allocator per Exhibit LMO-1 Actuals, Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490

[2]PE-MD MDGP01 A&G O&M allocator per Exhibit LMO-1 Actuals, Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490

THE POTOMAC EDISON COMPANY - MARYLAND
Capital Revenue Requirement - Vendor 1

Annual Depreciation	3.04%
Tax Life	20

Year	Month	PE Capital	MD Jurisdictional Allocator[1]	Distribution Allocator[2]	PE-MD Distribution Plant-In-Service	PE-MD Dist. Plant-In-Service Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Deferred Income Taxes	ADIT	Rate Base	Monthly Capital Revenue Requirement	TOIT: *Property Tax*	Total Revenue Requirement
2014	Jan-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Feb-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Mar-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Apr-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	May-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jun-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jul-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Aug-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Sep-14	$ 414.07	0.59138	0.90670	$ 222.02	$ 222.02	$ 0.28	$ 0.28	$ 221.74	$ (0.50)	$ (0.50)	$ 221.25			
	Oct-14	$ 414.06	0.59138	0.90670	$ 222.02	$ 444.05	$ 0.84	$ 1.12	$ 442.92	$ (1.10)	$ (1.60)	$ 441.32			
	Nov-14	$ 414.07	0.59138	0.90670	$ 222.03	$ 666.07	$ 1.41	$ 2.53	$ 663.54	$ (2.10)	$ (3.69)	$ 659.85			
	Dec-14	$ -	0.59138	0.90670	$ -	$ 666.07	$ 1.69	$ 4.22	$ 661.86	$ (2.02)	$ (5.71)	$ 656.14			
2015	Jan-15	$ 456.54	0.59138	0.90670	$ 244.80	$ 910.87	$ 2.00	$ 6.22	$ 904.65	$ (0.76)	$ (6.48)	$ 898.18			
	Feb-15	$ 740.97	0.59138	0.90670	$ 397.31	$ 1,308.18	$ 2.81	$ 9.03	$ 1,299.15	$ (0.91)	$ (7.39)	$ 1,291.76			
	Mar-15	$ 1,481.94	0.59138	0.90670	$ 794.62	$ 2,102.80	$ 4.32	$ 13.35	$ 2,089.45	$ (1.32)	$ (8.71)	$ 2,080.75			
	Apr-15	$ 740.97	0.59138	0.90670	$ 397.31	$ 2,500.11	$ 5.83	$ 19.18	$ 2,480.93	$ (1.36)	$ (10.06)	$ 2,470.87			
	May-15	$ 740.97	0.59138	0.90670	$ 397.31	$ 2,897.42	$ 6.84	$ 26.01	$ 2,871.41	$ (1.59)	$ (11.65)	$ 2,859.75			
	Jun-15	$ 6,826.68	0.59138	0.90670	$ 3,660.50	$ 6,557.92	$ 11.98	$ 37.99	$ 6,519.92	$ (5.57)	$ (17.23)	$ 6,502.70			
	Jul-15	$ 1,481.94	0.59138	0.90670	$ 794.62	$ 7,352.54	$ 17.62	$ 55.61	$ 7,296.93	$ (5.39)	$ (22.62)	$ 7,274.31			
	Aug-15	$ 740.97	0.59138	0.90670	$ 397.31	$ 7,749.85	$ 19.13	$ 74.74	$ 7,675.11	$ (5.79)	$ (28.41)	$ 7,646.70			
	Sep-15	$ 740.97	0.59138	0.90670	$ 397.31	$ 8,147.16	$ 20.14	$ 94.88	$ 8,052.28	$ (6.54)	$ (34.95)	$ 8,017.33			
	Oct-15	$ 740.97	0.59138	0.90670	$ 397.31	$ 8,544.47	$ 21.14	$ 116.02	$ 8,428.45	$ (7.63)	$ (42.58)	$ 8,385.87			
	Nov-15	$ -	0.59138	0.90670	$ -	$ 8,544.47	$ 21.65	$ 137.67	$ 8,406.80	$ (7.49)	$ (50.07)	$ 8,356.73			
	Dec-15	$ 740.96	0.59138	0.90670	$ 397.31	$ 8,941.77	$ 22.15	$ 159.82	$ 8,781.96	$ (11.45)	$ (61.53)	$ 8,720.43			
2016	Jan-16	$ 1,536.10	0.59138	0.90670	$ 823.66	$ 9,765.44	$ 23.70	$ 183.51	$ 9,581.93	$ (8.91)	$ (70.43)	$ 9,511.49			
	Feb-16	$ 768.04	0.59138	0.90670	$ 411.83	$ 10,177.26	$ 25.26	$ 208.77	$ 9,968.49	$ (8.86)	$ (79.30)	$ 9,889.20			
	Mar-16	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 234.55	$ 9,942.71	$ (8.72)	$ (88.01)	$ 9,854.70			
	Apr-16	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 260.34	$ 9,916.93	$ (8.72)	$ (96.73)	$ 9,820.19			
	May-16	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 286.12	$ 9,891.15	$ (8.72)	$ (105.45)	$ 9,785.69			
	Jun-16	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 311.90	$ 9,865.36	$ (8.72)	$ (114.17)	$ 9,751.19			
	Jul-16	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 337.68	$ 9,839.58	$ (8.72)	$ (122.89)	$ 9,716.69			
	Aug-16	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 363.47	$ 9,813.80	$ (8.72)	$ (131.61)	$ 9,682.19			
	Sep-16	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 389.25	$ 9,788.02	$ (8.72)	$ (140.33)	$ 9,647.68			
	Oct-16	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 415.03	$ 9,762.23	$ (8.72)	$ (149.05)	$ 9,613.18			
	Nov-16	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 440.81	$ 9,736.45	$ (8.72)	$ (157.77)	$ 9,578.68			
	Dec-16	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 466.60	$ 9,710.67	$ (8.72)	$ (166.49)	$ 9,544.18			
2017	Jan-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 492.38	$ 9,684.89	$ (8.57)	$ (175.05)	$ 9,509.83			
	Feb-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 518.16	$ 9,659.10	$ (8.57)	$ (183.62)	$ 9,475.48			
	Mar-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 543.94	$ 9,633.32	$ (8.57)	$ (192.19)	$ 9,441.14			
	Apr-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 569.73	$ 9,607.54	$ (8.57)	$ (200.75)	$ 9,406.79			
	May-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 595.51	$ 9,581.76	$ (8.57)	$ (209.32)	$ 9,372.44			
	Jun-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 621.29	$ 9,555.97	$ (8.57)	$ (217.88)	$ 9,338.09			
	Jul-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 647.07	$ 9,530.19	$ (8.57)	$ (226.45)	$ 9,303.75	$ 96.23	$ 8.31	$ 104.54
	Aug-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 672.85	$ 9,504.41	$ (8.57)	$ (235.01)	$ 9,269.40	$ 95.97	$ 8.31	$ 104.28
	Sep-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 698.64	$ 9,478.63	$ (8.57)	$ (243.58)	$ 9,235.05	$ 95.71	$ 8.31	$ 104.02
	Oct-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 724.42	$ 9,452.84	$ (8.57)	$ (252.14)	$ 9,200.70	$ 95.45	$ 8.31	$ 103.76
	Nov-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 750.20	$ 9,427.06	$ (8.57)	$ (260.71)	$ 9,166.36	$ 95.19	$ 8.31	$ 103.50
	Dec-17	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 775.98	$ 9,401.28	$ (8.57)	$ (269.27)	$ 9,132.01	$ 94.93	$ 8.31	$ 103.24
2018	Jan-18	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 801.77	$ 9,375.50	$ (7.39)	$ (276.66)	$ 9,098.83	$ 94.68	$ 8.31	$ 102.99
	Feb-18	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 827.55	$ 9,349.72	$ (7.39)	$ (284.05)	$ 9,065.66	$ 94.43	$ 8.31	$ 102.74
	Mar-18	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 853.33	$ 9,323.93	$ (7.39)	$ (291.45)	$ 9,032.49	$ 94.17	$ 8.31	$ 102.49
	Apr-18	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 879.11	$ 9,298.15	$ (7.39)	$ (298.84)	$ 8,999.31	$ 93.92	$ 8.31	$ 102.23
	May-18	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 904.90	$ 9,272.37	$ (7.39)	$ (306.23)	$ 8,966.14	$ 93.67	$ 8.31	$ 101.98
	Jun-18	$ -	0.59138	0.90670	$ -	$ 10,177.26	$ 25.78	$ 930.68	$ 9,246.59	$ (7.39)	$ (313.62)	$ 8,932.96	$ 93.42	$ 8.31	$ 101.73
		$ 18,980.20			$ 10,177.26										

Annual Revenue Requirement prior to new Depreciation Rates =	$	1,237.50
New Depreciation Rate effective March 23, 2019 =		2.66%
Annual Revenue Requirement after new Depreciation Rates =	$	1,198.83
Gross-Up with GRT & PSC Assessment Fee =	$	1,225.72
Gross-Up with Uncollectibles =	$	1,238.37
New Depreciation Rate[3] effective November 1, 2021 =		1.93%
Annual Revenue Requirement after new Depreciation Rates =	$	1,124.54
Gross-Up with GRT & PSC Assessment Fee =	$	1,149.76
Gross-Up with Uncollectibles =	$	1,161.63

[1]PE-MD CWIP allocator per Exhibit LMO-1 Actuals (page 11), Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490

[2]PE-MD Distribution CWIP allocator per Exhibit LMO-1 Actuals (page 11), Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490

[3]New depreciation rates were effective November 1, 2021 in accordance with Commission Order No. 89971 dated October 26, 2021 in Case No. 9490 Phase II

THE POTOMAC EDISON COMPANY - MARYLAND
Capital Revenue Requirement - Vendor 2

Annual Depreciation 3.04%
Tax Life 20

Year	Month	PE Capital	MD Jurisdictional Allocator[1]	Distribution Allocator[2]	PE-MD Distribution Plant-In-Service	PE-MD Dist. Plant-In-Service Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Deferred Income Taxes	ADIT	Rate Base	Monthly Capital Revenue Requirement	TOIT: *Property Tax*	Total Revenue Requirement
2014	Jan-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Feb-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Mar-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Apr-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	May-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jun-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jul-14	$ 754.11	0.59138	0.90670	$ 404.35	$ 404.35	$ 0.51	$ 0.51	$ 403.84	$ (0.55)	$ (0.55)	$ 403.29			
	Aug-14	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 1.54	$ 402.82	$ (0.41)	$ (0.97)	$ 401.85			
	Sep-14	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 2.56	$ 401.79	$ (0.41)	$ (1.38)	$ 400.41			
	Oct-14	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 3.59	$ 400.77	$ (0.41)	$ (1.80)	$ 398.97			
	Nov-14	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 4.61	$ 399.75	$ (0.41)	$ (2.21)	$ 397.54			
	Dec-14	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 5.63	$ 398.72	$ (0.41)	$ (2.62)	$ 396.10			
2015	Jan-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 6.66	$ 397.70	$ (0.39)	$ (3.01)	$ 394.69			
	Feb-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 7.68	$ 396.67	$ (0.39)	$ (3.40)	$ 393.27			
	Mar-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 8.71	$ 395.65	$ (0.39)	$ (3.78)	$ 391.86			
	Apr-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 9.73	$ 394.62	$ (0.39)	$ (4.17)	$ 390.45			
	May-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 10.76	$ 393.60	$ (0.39)	$ (4.56)	$ 389.04			
	Jun-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 11.78	$ 392.57	$ (0.39)	$ (4.95)	$ 387.63			
	Jul-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 12.80	$ 391.55	$ (0.39)	$ (5.33)	$ 386.22			
	Aug-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 13.83	$ 390.53	$ (0.39)	$ (5.72)	$ 384.80			
	Sep-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 14.85	$ 389.50	$ (0.39)	$ (6.11)	$ 383.39			
	Oct-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 15.88	$ 388.48	$ (0.39)	$ (6.50)	$ 381.98			
	Nov-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 16.90	$ 387.45	$ (0.39)	$ (6.88)	$ 380.57			
	Dec-15	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 17.93	$ 386.43	$ (0.39)	$ (7.27)	$ 379.16			
2016	Jan-16	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 18.95	$ 385.40	$ (0.34)	$ (7.61)	$ 377.79			
	Feb-16	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 19.98	$ 384.38	$ (0.34)	$ (7.95)	$ 376.43			
	Mar-16	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 21.00	$ 383.36	$ (0.34)	$ (8.28)	$ 375.07			
	Apr-16	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 22.02	$ 382.33	$ (0.34)	$ (8.62)	$ 373.71			
	May-16	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 23.05	$ 381.31	$ (0.34)	$ (8.96)	$ 372.35			
	Jun-16	$ -	0.59138	0.90670	$ -	$ 404.35	$ 1.02	$ 24.07	$ 380.28	$ (0.34)	$ (9.30)	$ 370.99			
	Jul-16	$ 212.29	0.59138	0.90670	$ 113.83	$ 518.18	$ 1.17	$ 25.24	$ 492.94	$ (0.49)	$ (9.79)	$ 483.15			
	Aug-16	$ 212.28	0.59138	0.90670	$ 113.83	$ 632.01	$ 1.46	$ 26.70	$ 605.31	$ (0.65)	$ (10.44)	$ 594.88			
	Sep-16	$ 212.28	0.59138	0.90670	$ 113.83	$ 745.84	$ 1.75	$ 28.44	$ 717.40	$ (0.86)	$ (11.30)	$ 706.09			
	Oct-16	$ 212.28	0.59138	0.90670	$ 113.83	$ 859.67	$ 2.03	$ 30.48	$ 829.19	$ (1.18)	$ (12.48)	$ 816.71			
	Nov-16	$ 212.28	0.59138	0.90670	$ 113.83	$ 973.49	$ 2.32	$ 32.80	$ 940.70	$ (1.68)	$ (14.16)	$ 926.54			
	Dec-16	$ 212.28	0.59138	0.90670	$ 113.83	$ 1,087.32	$ 2.61	$ 35.41	$ 1,051.91	$ (2.78)	$ (16.94)	$ 1,034.98			
2017	Jan-17	$ 7,498.69	0.59138	0.90670	$ 4,020.83	$ 5,108.15	$ 7.85	$ 43.26	$ 5,064.89	$ (3.00)	$ (19.94)	$ 5,044.95			
	Feb-17	$ 425.25	0.59138	0.90670	$ 228.02	$ 5,336.17	$ 13.23	$ 56.49	$ 5,279.69	$ (1.73)	$ (21.67)	$ 5,258.01			
	Mar-17	$ 425.25	0.59138	0.90670	$ 228.02	$ 5,564.19	$ 13.81	$ 70.29	$ 5,493.90	$ (1.81)	$ (23.48)	$ 5,470.41			
	Apr-17	$ 425.25	0.59138	0.90670	$ 228.02	$ 5,792.21	$ 14.38	$ 84.68	$ 5,707.54	$ (1.91)	$ (25.40)	$ 5,682.14			
	May-17	$ 425.25	0.59138	0.90670	$ 228.02	$ 6,020.23	$ 14.96	$ 99.64	$ 5,920.59	$ (2.05)	$ (27.45)	$ 5,893.15			
	Jun-17	$ 425.25	0.59138	0.90670	$ 228.02	$ 6,248.26	$ 15.54	$ 115.18	$ 6,133.07	$ (2.23)	$ (29.67)	$ 6,103.40			
	Jul-17	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 131.01	$ 6,117.25	$ (2.15)	$ (31.82)	$ 6,085.43	$ 61.91	$ 5.10	$ 67.01
	Aug-17	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 146.84	$ 6,101.42	$ (2.15)	$ (33.96)	$ 6,067.45	$ 61.77	$ 5.10	$ 66.87
	Sep-17	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 162.67	$ 6,085.59	$ (2.15)	$ (36.11)	$ 6,049.48	$ 61.63	$ 5.10	$ 66.74
	Oct-17	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 178.50	$ 6,069.76	$ (2.15)	$ (38.26)	$ 6,031.50	$ 61.50	$ 5.10	$ 66.60
	Nov-17	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 194.33	$ 6,053.93	$ (2.15)	$ (40.40)	$ 6,013.53	$ 61.36	$ 5.10	$ 66.46
	Dec-17	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 210.15	$ 6,038.10	$ (2.15)	$ (42.55)	$ 5,995.55	$ 61.23	$ 5.10	$ 66.33
2018	Jan-18	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 225.98	$ 6,022.27	$ (5.76)	$ (48.31)	$ 5,973.96	$ 61.06	$ 5.10	$ 66.17
	Feb-18	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 241.81	$ 6,006.44	$ (5.76)	$ (54.08)	$ 5,952.37	$ 60.90	$ 5.10	$ 66.00
	Mar-18	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 257.64	$ 5,990.61	$ (5.76)	$ (59.84)	$ 5,930.78	$ 60.74	$ 5.10	$ 65.84
	Apr-18	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 273.47	$ 5,974.79	$ (5.76)	$ (65.60)	$ 5,909.18	$ 60.57	$ 5.10	$ 65.67
	May-18	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 289.30	$ 5,958.96	$ (5.76)	$ (71.36)	$ 5,887.59	$ 60.41	$ 5.10	$ 65.51
	Jun-18	$ -	0.59138	0.90670	$ -	$ 6,248.26	$ 15.83	$ 305.13	$ 5,943.13	$ (5.76)	$ (77.13)	$ 5,866.00	$ 60.25	$ 5.10	$ 65.35
		$ 11,652.75			$ 6,248.26										

Annual Revenue Requirement prior to new Depreciation Rates =	$ 794.55
New Depreciation Rate effective March 23, 2019 =	2.66%
Annual Revenue Requirement after new Depreciation Rates =	$ 770.81
Gross-Up with GRT & PSC Assessment Fee =	$ 788.10
Gross-Up with Uncollectibles =	$ 796.24
New Depreciation Rate[3] effective November 1, 2021 =	1.93%
Annual Revenue Requirement after new Depreciation Rates =	$ 725.20
Gross-Up with GRT & PSC Assessment Fee =	$ 741.46
Gross-Up with Uncollectibles =	$ 749.12

[1]PE-MD CWIP allocator per Exhibit LMO-1 Actuals (page 11), Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490
[2]PE-MD Distribution CWIP allocator per Exhibit LMO-1 Actuals (page 11), Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490
[3]New depreciation rates were effective November 1, 2021 in accordance with Commission Order No. 89971 dated October 26, 2021 in Case No. 9490 Phase II

THE POTOMAC EDISON COMPANY - MARYLAND
Capital Revenue Requirement - Vendor 3

Annual Depreciation	3.04%
Tax Life	20

Year	Month	PE Capital	MD Jurisdictional Allocator[1]	Distribution Allocator[2]	PE-MD Distribution Plant-In-Service	PE-MD Dist. Plant-In-Service Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Deferred Income Taxes	ADIT	Rate Base	Monthly Capital Revenue Requirement	TOIT: *Property Tax*	Total Revenue Requirement
2014	Jan-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Feb-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Mar-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Apr-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	May-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jun-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jul-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Aug-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Sep-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Oct-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Nov-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Dec-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
2015	Jan-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Feb-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Mar-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Apr-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	May-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jun-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jul-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Aug-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Sep-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Oct-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Nov-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Dec-15	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
2016	Jan-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Feb-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Mar-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Apr-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	May-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jun-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jul-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Aug-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Sep-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Oct-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Nov-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Dec-16	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
2017	Jan-17	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Feb-17	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Mar-17	$ 8,561.70	0.59138	0.90670	$ 4,590.82	$ 4,590.82	$ 5.82	$ 5.82	$ 4,585.01	$ (3.14)	$ (3.14)	$ 4,581.87			
	Apr-17	$ -	0.59138	0.90670	$ -	$ 4,590.82	$ 11.63	$ 17.45	$ 4,573.38	$ (1.54)	$ (4.67)	$ 4,568.70			
	May-17	$ 8,561.70	0.59138	0.90670	$ 4,590.82	$ 9,181.64	$ 17.45	$ 34.89	$ 9,146.75	$ (5.86)	$ (10.53)	$ 9,136.22			
	Jun-17	$ -	0.59138	0.90670	$ -	$ 9,181.64	$ 23.26	$ 58.15	$ 9,123.49	$ (4.26)	$ (14.79)	$ 9,108.70			
	Jul-17	$ -	0.59138	0.90670	$ -	$ 9,181.64	$ 23.26	$ 81.41	$ 9,100.23	$ (4.26)	$ (19.05)	$ 9,081.18	$ 92.02	$ 7.50	$ 99.52
	Aug-17	$ 8,561.70	0.59138	0.90670	$ 4,590.82	$ 13,772.46	$ 29.08	$ 110.49	$ 13,661.98	$ (12.13)	$ (31.18)	$ 13,630.79	$ 132.29	$ 11.25	$ 143.53
	Sep-17	$ -	0.59138	0.90670	$ -	$ 13,772.46	$ 34.89	$ 145.38	$ 13,627.09	$ (10.53)	$ (41.71)	$ 13,585.37	$ 137.76	$ 11.25	$ 149.00
	Oct-17	$ -	0.59138	0.90670	$ -	$ 13,772.46	$ 34.89	$ 180.27	$ 13,592.20	$ (10.53)	$ (52.25)	$ 13,539.95	$ 137.41	$ 11.25	$ 148.66
	Nov-17	$ -	0.59138	0.90670	$ -	$ 13,772.46	$ 34.89	$ 215.16	$ 13,557.31	$ (10.53)	$ (62.78)	$ 13,494.53	$ 137.07	$ 11.25	$ 148.32
	Dec-17	$ 8,561.70	0.59138	0.90670	$ 4,590.82	$ 18,363.28	$ 40.71	$ 255.86	$ 18,107.42	$ (56.31)	$ (119.09)	$ 17,988.34	$ 176.91	$ 15.00	$ 191.91
2018	Jan-18	$ -	0.59138	0.90670	$ -	$ 18,363.28	$ 46.52	$ 302.38	$ 18,060.90	$ (17.60)	$ (136.68)	$ 17,924.22	$ 182.24	$ 15.00	$ 197.24
	Feb-18	$ -	0.59138	0.90670	$ -	$ 18,363.28	$ 46.52	$ 348.90	$ 18,014.38	$ (17.60)	$ (154.28)	$ 17,860.10	$ 181.75	$ 15.00	$ 196.75
	Mar-18	$ -	0.59138	0.90670	$ -	$ 18,363.28	$ 46.52	$ 395.42	$ 17,967.86	$ (17.60)	$ (171.88)	$ 17,795.98	$ 181.27	$ 15.00	$ 196.26
	Apr-18	$ -	0.59138	0.90670	$ -	$ 18,363.28	$ 46.52	$ 441.94	$ 17,921.34	$ (17.60)	$ (189.48)	$ 17,731.86	$ 180.78	$ 15.00	$ 195.78
	May-18	$ -	0.59138	0.90670	$ -	$ 18,363.28	$ 46.52	$ 488.46	$ 17,874.82	$ (17.60)	$ (207.07)	$ 17,667.75	$ 180.30	$ 15.00	$ 195.29
	Jun-18	$ -	0.59138	0.90670	$ -	$ 18,363.28	$ 46.52	$ 534.98	$ 17,828.30	$ (17.60)	$ (224.67)	$ 17,603.63	$ 179.81	$ 15.00	$ 194.81
		$ 34,246.80			$ 18,363.28										

Annual Revenue Requirement prior to new Depreciation Rates =	$	2,057.07
New Depreciation Rate effective March 23, 2019 =		2.66%
Annual Revenue Requirement after new Depreciation Rates =	$	1,997.47
Gross-Up with GRT & PSC Assessment Fee =	$	2,042.27
Gross-Up with Uncollectibles =	$	2,063.36
New Depreciation Rate[3] effective November 1, 2021 =		1.93%
Annual Revenue Requirement after new Depreciation Rates =	$	1,882.96
Gross-Up with GRT & PSC Assessment Fee =	$	1,925.20
Gross-Up with Uncollectibles =	$	1,945.08

[1]PE-MD CWIP allocator per Exhibit LMO-1 Actuals (page 11), Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490
[2]PE-MD Distribution CWIP allocator per Exhibit LMO-1 Actuals (page 11), Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490
[3]New depreciation rates were effective November 1, 2021 in accordance with Commission Order No. 89971 dated October 26, 2021 in Case No. 9490 Phase II

THE POTOMAC EDISON COMPANY - MARYLAND
Summary Sponsorship/Advertising

	Prior to Nov 1, 2021		Effective[1] Nov 1, 2021	
	MD		MD	
Sponsorship/Advertising				
O&M Annual Rev Req	$	194,146	$	194,146
Capital Annual Rev Req	$	1,792	$	1,685
	$	195,939	$	195,831

[1]New depreciation rates were effective November 1, 2021 in accordance with Commission Order No. 89971 dated October 26, 2021 in Case No. 9490 Phase II, which subsequently lowered the capital revenue

THE POTOMAC EDISON COMPANY - MARYLAND
Sponsorship/Advertising
O&M Recorded to Account 923

		Total Company PE10
2017	Jul	$ 13,739.92
2017	Aug	$ 10,390.65
2017	Sep	$ 97,861.18
2017	Oct	$ 38,646.11
2017	Nov	$ 23,173.78
2017	Dec	$ 161,017.87
2018	Jan	$ 1,356.26
2018	Feb	$ 5,281.38
2018	Mar	$ 5,422.18
2018	Apr	$ 14,140.15
2018	May	$ 11,642.99
2018	Jun	$ 11,404.55
	Total PE =	$ 394,077.04

Maryland	Sponsorship/ Advertising
MD rate case test year O&M =	$ 394,077.04
PE-MD Allocator[1] =	58.116%
PE-MD rate case test year O&M =	$ 229,021.81
PE-MD Distribution Allocator[2] =	82.065%
PE-MD Distribution rate case test year O&M =	$ 187,946.75
Gross-Up with GRT & PSC Assessment Fee =	$ 192,162.21
Gross-Up with GRT, PSC Fee & Uncollectibles =	$ 194,146.39

[1]PE-MD GP01 A&G O&M allocator per Exhibit LMO-1 Actuals, Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490

[2]PE-MD MDGP01 A&G O&M allocator per Exhibit LMO-1 Actuals, Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490

THE POTOMAC EDISON COMPANY - MARYLAND
Capital Revenue Requirement

Annual Depreciation	3.04%
Tax Life	20

Year	Month	PE Capital	MD Jurisdictional Allocator[1]	Distribution Allocator[2]	PE-MD Distribution Plant-In-Service	PE-MD Dist. Plant-In-Service Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Deferred Income Taxes	ADIT	Rate Base	Monthly Capital Revenue Requirement	TOIT: *Property Tax*	Total Revenue Requirement
2014	Jan-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Feb-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Mar-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Apr-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	May-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jun-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jul-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Aug-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Sep-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Oct-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Nov-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Dec-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
2015	Jan-15	$ 556.07	0.59138	0.90670	$ 298.17	$ 298.17	$ 0.38	$ 0.38	$ 297.79	$ (0.15)	$ (0.15)	$ 297.64			
	Feb-15	$ 68.61	0.59138	0.90670	$ 36.79	$ 334.96	$ 0.80	$ 1.18	$ 333.78	$ (0.07)	$ (0.22)	$ 333.55			
	Mar-15	$ 2,325.83	0.59138	0.90670	$ 1,247.12	$ 1,582.08	$ 2.43	$ 3.61	$ 1,578.47	$ (0.91)	$ (1.13)	$ 1,577.34			
	Apr-15	$ -	0.59138	0.90670	$ -	$ 1,582.08	$ 4.01	$ 7.62	$ 1,574.46	$ (0.47)	$ (1.61)	$ 1,572.85			
	May-15	$ 22.30	0.59138	0.90670	$ 11.96	$ 1,594.03	$ 4.02	$ 11.64	$ 1,582.39	$ (0.49)	$ (2.09)	$ 1,580.30			
	Jun-15	$ 1,993.57	0.59138	0.90670	$ 1,068.96	$ 2,663.00	$ 5.39	$ 17.03	$ 2,645.96	$ (1.69)	$ (3.78)	$ 2,642.19			
	Jul-15	$ -	0.59138	0.90670	$ -	$ 2,663.00	$ 6.75	$ 23.78	$ 2,639.22	$ (1.31)	$ (5.09)	$ 2,634.13			
	Aug-15	$ -	0.59138	0.90670	$ -	$ 2,663.00	$ 6.75	$ 30.52	$ 2,632.47	$ (1.31)	$ (6.40)	$ 2,626.07			
	Sep-15	$ -	0.59138	0.90670	$ -	$ 2,663.00	$ 6.75	$ 37.27	$ 2,625.73	$ (1.31)	$ (7.72)	$ 2,618.01			
	Oct-15	$ 12.01	0.59138	0.90670	$ 6.44	$ 2,669.43	$ 6.75	$ 44.02	$ 2,625.41	$ (1.33)	$ (9.05)	$ 2,616.36			
	Nov-15	$ 177.16	0.59138	0.90670	$ 94.99	$ 2,764.43	$ 6.88	$ 50.91	$ 2,713.52	$ (1.79)	$ (10.84)	$ 2,702.68			
	Dec-15	$ -	0.59138	0.90670	$ -	$ 2,764.43	$ 7.00	$ 57.91	$ 2,706.52	$ (1.75)	$ (12.59)	$ 2,693.92			
2016	Jan-16	$ 2,178.98	0.59138	0.90670	$ 1,168.38	$ 3,932.81	$ 8.48	$ 66.39	$ 3,866.41	$ (3.25)	$ (15.84)	$ 3,850.58			
	Feb-16	$ -	0.59138	0.90670	$ -	$ 3,932.81	$ 9.96	$ 76.36	$ 3,856.45	$ (2.84)	$ (18.68)	$ 3,837.77			
	Mar-16	$ -	0.59138	0.90670	$ -	$ 3,932.81	$ 9.96	$ 86.32	$ 3,846.49	$ (2.84)	$ (21.52)	$ 3,824.97			
	Apr-16	$ -	0.59138	0.90670	$ -	$ 3,932.81	$ 9.96	$ 96.28	$ 3,836.52	$ (2.84)	$ (24.36)	$ 3,812.17			
	May-16	$ -	0.59138	0.90670	$ -	$ 3,932.81	$ 9.96	$ 106.25	$ 3,826.56	$ (2.84)	$ (27.19)	$ 3,799.37			
	Jun-16	$ 2,006.73	0.59138	0.90670	$ 1,076.02	$ 5,008.82	$ 11.33	$ 117.57	$ 4,891.25	$ (4.05)	$ (31.25)	$ 4,860.00			
	Jul-16	$ 1,906.76	0.59138	0.90670	$ 1,022.41	$ 6,031.24	$ 13.98	$ 131.56	$ 5,899.68	$ (5.08)	$ (36.32)	$ 5,863.36			
	Aug-16	$ -	0.59138	0.90670	$ -	$ 6,031.24	$ 15.28	$ 146.84	$ 5,884.40	$ (4.72)	$ (41.04)	$ 5,843.36			
	Sep-16	$ 4,139.28	0.59138	0.90670	$ 2,219.50	$ 8,250.73	$ 18.09	$ 164.93	$ 8,085.81	$ (9.67)	$ (50.72)	$ 8,035.09			
	Oct-16	$ 521.36	0.59138	0.90670	$ 279.55	$ 8,530.29	$ 21.26	$ 186.18	$ 8,344.11	$ (9.76)	$ (60.48)	$ 8,283.62			
	Nov-16	$ 1,160.31	0.59138	0.90670	$ 622.17	$ 9,152.45	$ 22.40	$ 208.58	$ 8,943.87	$ (12.66)	$ (73.14)	$ 8,870.73			
	Dec-16	$ 173.79	0.59138	0.90670	$ 93.18	$ 9,245.64	$ 23.30	$ 231.88	$ 9,013.75	$ (13.37)	$ (86.51)	$ 8,927.24			
2017	Jan-17	$ 2,220.94	0.59138	0.90670	$ 1,190.88	$ 10,436.51	$ 24.93	$ 256.81	$ 10,179.70	$ (9.13)	$ (95.64)	$ 10,084.06			
	Feb-17	$ 342.47	0.59138	0.90670	$ 183.63	$ 10,620.15	$ 26.67	$ 283.49	$ 10,336.66	$ (8.82)	$ (104.46)	$ 10,232.20			
	Mar-17	$ -	0.59138	0.90670	$ -	$ 10,620.15	$ 26.90	$ 310.39	$ 10,309.76	$ (8.75)	$ (113.21)	$ 10,196.54			
	Apr-17	$ -	0.59138	0.90670	$ -	$ 10,620.15	$ 26.90	$ 337.30	$ 10,282.85	$ (8.75)	$ (121.97)	$ 10,160.89			
	May-17	$ -	0.59138	0.90670	$ -	$ 10,620.15	$ 26.90	$ 364.20	$ 10,255.95	$ (8.75)	$ (130.72)	$ 10,125.23			
	Jun-17	$ 68.49	0.59138	0.90670	$ 36.73	$ 10,656.87	$ 26.95	$ 391.15	$ 10,265.72	$ (8.80)	$ (139.52)	$ 10,126.21			
	Jul-17	$ 1,784.50	0.59138	0.90670	$ 956.85	$ 11,613.73	$ 28.21	$ 419.36	$ 11,194.37	$ (10.10)	$ (149.61)	$ 11,044.76	$ 111.84	$ 9.48	$ 121.32
	Aug-17	$ 446.42	0.59138	0.90670	$ 239.37	$ 11,853.10	$ 29.72	$ 449.08	$ 11,404.02	$ (10.17)	$ (159.78)	$ 11,244.23	$ 114.86	$ 9.68	$ 124.54
	Sep-17	$ 72.77	0.59138	0.90670	$ 39.02	$ 11,892.12	$ 30.08	$ 479.16	$ 11,412.96	$ (10.18)	$ (169.96)	$ 11,243.00	$ 115.21	$ 9.71	$ 124.92
	Oct-17	$ 4,175.00	0.59138	0.90670	$ 2,238.66	$ 14,130.78	$ 32.96	$ 512.12	$ 13,618.65	$ (17.08)	$ (187.04)	$ 13,431.61	$ 134.66	$ 11.54	$ 146.20
	Nov-17	$ 1.93	0.59138	0.90670	$ 1.03	$ 14,131.81	$ 35.80	$ 547.92	$ 13,583.89	$ (16.31)	$ (203.35)	$ 13,380.54	$ 137.11	$ 11.54	$ 148.66
	Dec-17	$ 8.06	0.59138	0.90670	$ 4.32	$ 14,136.13	$ 35.81	$ 583.73	$ 13,552.40	$ (16.35)	$ (219.70)	$ 13,332.70	$ 136.76	$ 11.54	$ 148.30
2018	Jan-18	$ -	0.59138	0.90670	$ -	$ 14,136.13	$ 35.81	$ 619.54	$ 13,516.59	$ (12.08)	$ (231.78)	$ 13,284.81	$ 136.40	$ 11.54	$ 147.95
	Feb-18	$ 2,548.24	0.59138	0.90670	$ 1,366.38	$ 15,502.51	$ 37.54	$ 657.08	$ 14,845.43	$ (12.89)	$ (244.67)	$ 14,600.76	$ 148.10	$ 12.66	$ 160.76
	Mar-18	$ -	0.59138	0.90670	$ -	$ 15,502.51	$ 39.27	$ 696.36	$ 14,806.15	$ (12.41)	$ (257.08)	$ 14,549.08	$ 149.44	$ 12.66	$ 162.10
	Apr-18	$ -	0.59138	0.90670	$ -	$ 15,502.51	$ 39.27	$ 735.63	$ 14,766.88	$ (12.41)	$ (269.49)	$ 14,497.40	$ 149.04	$ 12.66	$ 161.71
	May-18	$ -	0.59138	0.90670	$ -	$ 15,502.51	$ 39.27	$ 774.90	$ 14,727.61	$ (12.41)	$ (281.90)	$ 14,445.71	$ 148.65	$ 12.66	$ 161.31
	Jun-18	$ 2,427.50	0.59138	0.90670	$ 1,301.63	$ 16,804.14	$ 40.92	$ 815.82	$ 15,988.32	$ (13.87)	$ (295.77)	$ 15,692.55	$ 159.74	$ 13.72	$ 173.47
		$ 31,339.07			$ 16,804.14										

Annual Revenue Requirement prior to new Depreciation Rates =	$ 1,781.23
New Depreciation Rate effective March 23, 2019 =	2.66%
Annual Revenue Requirement after new Depreciation Rates =	$ 1,734.96
Gross-Up with GRT & PSC Assessment Fee =	$ 1,773.88
Gross-Up with Uncollectibles =	$ 1,792.19
New Depreciation Rate[3] effective November 1, 2021 =	1.93%
Annual Revenue Requirement after new Depreciation Rates =	$ 1,631.11
Gross-Up with GRT & PSC Assessment Fee =	$ 1,667.70
Gross-Up with Uncollectibles =	$ 1,684.92

[1]PE-MD CWIP allocator per Exhibit LMO-1 Actuals (page 11), Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490
[2]PE-MD Distribution CWIP allocator per Exhibit LMO-1 Actuals (page 11), Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490
[3]New depreciation rates were effective November 1, 2021 in accordance with Commission Order No. 89971 dated October 26, 2021 in Case No. 9490 Phase II

THE POTOMAC EDISON COMPANY - MARYLAND
Summary Miscellaneous*

	Prior to Nov 1, 2021		Effective[1] Nov 1, 2021	
	MD		MD	
Total				
O&M Annual Rev Req	$	62,676	$	62,676
Capital Annual Rev Req	$	5,745	$	5,402
	$	68,421	$	68,078

*Includes amounts related to FE Foundation, Lobbying, FE Products, IT for FE Products, Vendors, and Trade Association Dues

[1]New depreciation rates were effective November 1, 2021 in accordance with Commission Order No. 89971 dated October 26, 2021 in Case No. 9490 Phase II, which subsequently lowered the capital revenue

THE POTOMAC EDISON COMPANY - MARYLAND
Miscellaneous
O&M Recorded to Accounts 923, 926 and 403

	FERC 923 PE10	FERC 926 PE10	FERC 403 PE10	Total PE10
2017 Jul	$ 6,989.37	$ 1,045.44	$ 17.71	$ 8,052.52
2017 Aug	$ 6,989.37	$ 1,045.44	$ 17.71	$ 8,052.52
2017 Sep	$ 6,989.37	$ 1,045.44	$ 17.71	$ 8,052.52
2017 Oct	$ 7,503.63	$ 1,045.44	$ 17.71	$ 8,566.77
2017 Nov	$ 6,989.37	$ 1,045.44	$ 17.71	$ 8,052.52
2017 Dec	$ 8,772.06	$ 1,045.44	$ 17.71	$ 9,835.21
2018 Jan	$ 8,843.27	$ 1,161.87	$ 17.20	$ 10,022.34
2018 Feb	$ 8,846.21	$ 1,161.87	$ 17.20	$ 10,025.28
2018 Mar	$ 10,158.81	$ 1,161.87	$ 17.20	$ 11,337.88
2018 Apr	$ 8,860.09	$ 1,161.87	$ 17.20	$ 10,039.16
2018 May	$ 8,849.78	$ 1,161.87	$ 17.20	$ 10,028.85
2018 Jun	$ 22,209.64	$ 1,161.87	$ 17.20	$ 23,388.71
Total PE =	$ 112,000.98	$ 13,243.88	$ 209.41	$ 125,454.28

Maryland	FERC 923	FERC 926	FERC 403	Total
MD rate case test year O&M =	$ 112,000.98	$ 13,243.88	$ 209.41	$ 125,454.28
PE-MD Allocator[1] =	58.116%	58.670%	60.794%	
PE-MD rate case test year O&M =	$ 65,090.49	$ 7,770.19	$ 127.31	$ 72,987.99
PE-MD Distribution Allocator[2] =	82.065%	91.902%	91.902%	
PE-MD Distribution rate case test year O&M =	$ 53,416.51	$ 7,140.96	$ 117.00	$ 60,674.47
Gross-Up with GRT & PSC Assessment Fee =	$ 54,614.59	$ 7,301.12	$ 119.62	$ 62,035.34
Gross-Up with GRT, PSC Fee & Uncollectibles =	$ 55,178.52	$ 7,376.51	$ 120.86	$ 62,675.89

[1]PE-MD allocators per Exhibit LMO-1 Actuals, Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490
[2]PE-MD allocators per Exhibit LMO-1 Actuals, Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490

THE POTOMAC EDISON COMPANY - MARYLAND
Capital Revenue Requirement

Annual Depreciation 3.04%
Tax Life 20

Year	Month	PE Capital	MD Jurisdictional Allocator[1]	Distribution Allocator[2]	PE-MD Distribution Plant-In-Service	PE-MD Dist. Plant-In-Service Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Deferred Income Taxes	ADIT	Rate Base	Monthly Capital Revenue Requirement	TOIT: *Property Tax*	Total Revenue Requirement
2014	Jan-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Feb-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Mar-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Apr-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	May-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jun-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Jul-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Aug-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Sep-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Oct-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Nov-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	Dec-14	$ -	0.59138	0.90670	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
2015	Jan-15	$ 1,524.83	0.59138	0.90670	$ 817.62	$ 817.62	$ 1.04	$ 1.04	$ 816.58	$ (0.42)	$ (0.42)	$ 816.17			
	Feb-15	$ 1,524.83	0.59138	0.90670	$ 817.62	$ 1,635.24	$ 3.11	$ 4.14	$ 1,631.10	$ (0.62)	$ (1.03)	$ 1,630.06			
	Mar-15	$ 1,524.83	0.59138	0.90670	$ 817.62	$ 2,452.86	$ 5.18	$ 9.32	$ 2,443.54	$ (0.89)	$ (1.92)	$ 2,441.62			
	Apr-15	$ 1,524.83	0.59138	0.90670	$ 817.62	$ 3,270.48	$ 7.25	$ 16.57	$ 3,253.91	$ (1.26)	$ (3.18)	$ 3,250.73			
	May-15	$ 1,524.83	0.59138	0.90670	$ 817.62	$ 4,088.10	$ 9.32	$ 25.89	$ 4,062.21	$ (1.74)	$ (4.92)	$ 4,057.29			
	Jun-15	$ 1,524.83	0.59138	0.90670	$ 817.62	$ 4,905.72	$ 11.39	$ 37.28	$ 4,868.44	$ (2.38)	$ (7.30)	$ 4,861.14			
	Jul-15	$ 1,524.83	0.59138	0.90670	$ 817.62	$ 5,723.34	$ 13.46	$ 50.75	$ 5,672.60	$ (3.21)	$ (10.51)	$ 5,662.09			
	Aug-15	$ 1,524.83	0.59138	0.90670	$ 817.62	$ 6,540.96	$ 15.53	$ 66.28	$ 6,474.68	$ (4.33)	$ (14.84)	$ 6,459.84			
	Sep-15	$ 2,382.42	0.59138	0.90670	$ 1,277.46	$ 7,818.43	$ 18.19	$ 84.47	$ 7,733.96	$ (6.90)	$ (21.73)	$ 7,712.22			
	Oct-15	$ 1,524.83	0.59138	0.90670	$ 817.62	$ 8,636.05	$ 20.84	$ 105.31	$ 8,530.73	$ (8.98)	$ (30.71)	$ 8,500.02			
	Nov-15	$ 2,553.93	0.59138	0.90670	$ 1,369.43	$ 10,005.48	$ 23.61	$ 128.93	$ 9,876.55	$ (15.28)	$ (45.99)	$ 9,830.56			
	Dec-15	$ 1,524.83	0.59138	0.90670	$ 817.62	$ 10,823.10	$ 26.38	$ 155.31	$ 10,667.79	$ (22.96)	$ (68.95)	$ 10,598.84			
2016	Jan-16	$ 2,127.45	0.59138	0.90670	$ 1,140.75	$ 11,963.85	$ 28.86	$ 184.17	$ 11,779.67	$ (10.96)	$ (79.90)	$ 11,699.77			
	Feb-16	$ 2,137.88	0.59138	0.90670	$ 1,146.34	$ 13,110.19	$ 31.76	$ 215.93	$ 12,894.25	$ (11.23)	$ (91.14)	$ 12,803.12			
	Mar-16	$ 2,127.45	0.59138	0.90670	$ 1,140.75	$ 14,250.93	$ 34.66	$ 250.59	$ 14,000.34	$ (11.61)	$ (102.75)	$ 13,897.60			
	Apr-16	$ 2,127.45	0.59138	0.90670	$ 1,140.75	$ 15,391.68	$ 37.55	$ 288.14	$ 15,103.55	$ (12.13)	$ (114.87)	$ 14,988.67			
	May-16	$ 2,679.07	0.59138	0.90670	$ 1,436.53	$ 16,828.21	$ 40.81	$ 328.95	$ 16,499.26	$ (13.08)	$ (127.96)	$ 16,371.31			
	Jun-16	$ 2,127.45	0.59138	0.90670	$ 1,140.75	$ 17,968.96	$ 44.08	$ 373.03	$ 17,595.93	$ (13.86)	$ (141.82)	$ 17,454.12			
	Jul-16	$ 2,127.45	0.59138	0.90670	$ 1,140.75	$ 19,109.71	$ 46.97	$ 419.99	$ 18,689.72	$ (15.03)	$ (156.85)	$ 18,532.87			
	Aug-16	$ 2,127.45	0.59138	0.90670	$ 1,140.75	$ 20,250.46	$ 49.86	$ 469.85	$ 19,780.61	$ (16.59)	$ (173.44)	$ 19,607.17			
	Sep-16	$ 4,560.45	0.59138	0.90670	$ 2,445.33	$ 22,695.79	$ 54.40	$ 524.25	$ 22,171.54	$ (21.65)	$ (195.09)	$ 21,976.45			
	Oct-16	$ 2,947.95	0.59138	0.90670	$ 1,580.70	$ 24,276.49	$ 59.50	$ 583.74	$ 23,692.75	$ (25.68)	$ (220.77)	$ 23,471.98			
	Nov-16	$ 2,475.02	0.59138	0.90670	$ 1,327.12	$ 25,603.61	$ 63.18	$ 646.93	$ 24,956.68	$ (31.52)	$ (252.29)	$ 24,704.40			
	Dec-16	$ 2,130.00	0.59138	0.90670	$ 1,142.12	$ 26,745.72	$ 66.31	$ 713.23	$ 26,032.49	$ (42.44)	$ (294.73)	$ 25,737.76			
2017	Jan-17	$ 2,440.08	0.59138	0.90670	$ 1,308.38	$ 28,054.11	$ 69.41	$ 782.65	$ 27,271.46	$ (24.95)	$ (319.68)	$ 26,951.78			
	Feb-17	$ 2,429.80	0.59138	0.90670	$ 1,302.87	$ 29,356.98	$ 72.72	$ 855.37	$ 28,501.61	$ (25.27)	$ (344.95)	$ 28,156.66			
	Mar-17	$ 2,429.80	0.59138	0.90670	$ 1,302.87	$ 30,659.85	$ 76.02	$ 931.39	$ 29,728.46	$ (25.70)	$ (370.65)	$ 29,357.81			
	Apr-17	$ 2,429.80	0.59138	0.90670	$ 1,302.87	$ 31,962.72	$ 79.32	$ 1,010.71	$ 30,952.01	$ (26.29)	$ (396.94)	$ 30,555.07			
	May-17	$ 2,772.27	0.59138	0.90670	$ 1,486.50	$ 33,449.22	$ 82.86	$ 1,093.57	$ 32,355.66	$ (27.23)	$ (424.17)	$ 31,931.49			
	Jun-17	$ 4,204.81	0.59138	0.90670	$ 2,254.64	$ 35,703.86	$ 87.59	$ 1,181.16	$ 34,522.70	$ (29.25)	$ (453.42)	$ 34,069.28			
	Jul-17	$ 2,429.80	0.59138	0.90670	$ 1,302.87	$ 37,006.73	$ 92.10	$ 1,273.26	$ 35,733.47	$ (30.25)	$ (483.68)	$ 35,249.79	$ 359.01	$ 30.22	$ 389.23
	Aug-17	$ 2,429.80	0.59138	0.90670	$ 1,302.87	$ 38,309.60	$ 95.40	$ 1,368.66	$ 36,940.94	$ (32.03)	$ (515.71)	$ 36,425.23	$ 371.21	$ 31.29	$ 402.49
	Sep-17	$ 2,429.80	0.59138	0.90670	$ 1,302.87	$ 39,612.48	$ 98.70	$ 1,467.36	$ 38,145.11	$ (34.49)	$ (550.20)	$ 37,594.91	$ 383.36	$ 32.35	$ 415.71
	Oct-17	$ 3,103.20	0.59138	0.90670	$ 1,663.95	$ 41,276.43	$ 102.46	$ 1,569.82	$ 39,706.60	$ (39.18)	$ (589.37)	$ 39,117.23	$ 398.65	$ 33.71	$ 432.36
	Nov-17	$ 2,429.80	0.59138	0.90670	$ 1,302.87	$ 42,579.30	$ 106.22	$ 1,676.04	$ 40,903.26	$ (44.86)	$ (634.24)	$ 40,269.02	$ 411.13	$ 34.77	$ 445.90
	Dec-17	$ 2,686.66	0.59138	0.90670	$ 1,440.60	$ 44,019.89	$ 109.69	$ 1,785.73	$ 42,234.16	$ (58.77)	$ (693.01)	$ 41,541.15	$ 424.23	$ 35.95	$ 460.18
2018	Jan-18	$ 2,349.28	0.59138	0.90670	$ 1,259.69	$ 45,279.59	$ 113.11	$ 1,898.84	$ 43,380.74	$ (38.26)	$ (731.28)	$ 42,649.47	$ 436.05	$ 36.98	$ 473.02
	Feb-18	$ 2,349.28	0.59138	0.90670	$ 1,259.69	$ 46,539.28	$ 116.30	$ 2,015.15	$ 44,524.13	$ (38.57)	$ (769.84)	$ 43,754.29	$ 447.60	$ 38.01	$ 485.61
	Mar-18	$ 4,066.25	0.59138	0.90670	$ 2,180.34	$ 48,719.62	$ 120.66	$ 2,135.81	$ 46,583.81	$ (39.62)	$ (809.46)	$ 45,774.35	$ 467.26	$ 39.79	$ 507.04
	Apr-18	$ 2,349.28	0.59138	0.90670	$ 1,259.69	$ 49,979.31	$ 125.02	$ 2,260.83	$ 47,718.49	$ (39.86)	$ (849.32)	$ 46,869.16	$ 479.90	$ 40.82	$ 520.72
	May-18	$ 2,349.28	0.59138	0.90670	$ 1,259.69	$ 51,239.01	$ 128.21	$ 2,389.04	$ 48,849.97	$ (40.61)	$ (889.93)	$ 47,960.04	$ 491.35	$ 41.85	$ 533.20
	Jun-18	$ 19,831.21	0.59138	0.90670	$ 10,633.58	$ 61,872.59	$ 143.27	$ 2,532.31	$ 59,340.27	$ (52.14)	$ (942.07)	$ 58,398.20	$ 585.46	$ 50.53	$ 635.98
		$ 115,389.96			$ 61,872.59										

Annual Revenue Requirement prior to new Depreciation Rates = $ 5,701.46
New Depreciation Rate effective March 23, 2019 = 2.66%
Annual Revenue Requirement after new Depreciation Rates = $ 5,561.57
Gross-Up with GRT & PSC Assessment Fee = $ 5,686.31
Gross-Up with Uncollectibles = $ 5,745.02

New Depreciation Rate[3] effective November 1, 2021 = 1.93%
Annual Revenue Requirement after new Depreciation Rates = $ 5,229.15
Gross-Up with GRT & PSC Assessment Fee = $ 5,346.44
Gross-Up with Uncollectibles = $ 5,401.64

[1]PE-MD CWIP allocator per Exhibit LMO-1 Actuals (page 11), Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490
[2]PE-MD Distribution CWIP allocator per Exhibit LMO-1 Actuals (page 11), Distribution Base Rate Filing dated October 22, 2018 in Case No. 9490
[3]New depreciation rates were effective November 1, 2021 in accordance with Commission Order No. 89971 dated October 26, 2021 in Case No. 9490 Phase II

THE POTOMAC EDISON COMPANY - MARYLAND **Exhibit RV-4**

Principal and Carrying Charge Calculation

Case No. 9667

		Case No. 9667
Effective March 23, 2019		
O&M Revenue Req	$	33,490.42
Capital Revenue Req		4,097.97
	$	37,588.39
Effective November 1, 2021		
O&M Revenue Req	$	33,490.42
Capital Revenue Req		3,855.83
	$	37,346.25

PSC Ordered ROR	7.15%	thru Oct 18, 2023
Proposed ROR	7.54%	after Oct 18, 2023

	Total Before Carrying Charge	ROR Daily Carrying Charge %	Days in Month	Compounded Carrying Charge	Total with Carrying Charge	Cumulative Principal	Cumulative Carrying Charge	Cumulative Principal + Carrying Charge
Mar 23-31, 2019	$ 926.84	0.02%	9	$ 1.63	$ 928.47	$ 926.84	$ 1.63	$ 928.47
Apr 2019	$ 3,089.46	0.02%	30	$ 23.61	$ 3,113.07	$ 4,016.30	$ 25.24	$ 4,041.54
May 2019	$ 3,192.44	0.02%	31	$ 43.93	$ 3,236.37	$ 7,208.74	$ 69.17	$ 7,277.91
Jun 2019	$ 3,089.46	0.02%	30	$ 60.93	$ 3,150.39	$ 10,298.20	$ 130.10	$ 10,428.30
Jul 2019	$ 3,192.44	0.02%	31	$ 82.71	$ 3,275.15	$ 13,490.64	$ 212.81	$ 13,703.45
Aug 2019	$ 3,192.44	0.02%	31	$ 102.60	$ 3,295.04	$ 16,683.08	$ 315.41	$ 16,998.49
Sep 2019	$ 3,089.46	0.02%	30	$ 118.05	$ 3,207.51	$ 19,772.54	$ 433.46	$ 20,206.00
Oct 2019	$ 3,192.44	0.02%	31	$ 142.09	$ 3,334.53	$ 22,964.98	$ 575.55	$ 23,540.53
Nov 2019	$ 3,089.46	0.02%	30	$ 156.50	$ 3,245.96	$ 26,054.44	$ 732.05	$ 26,786.49
Dec 2019	$ 3,192.44	0.02%	31	$ 182.05	$ 3,374.49	$ 29,246.88	$ 914.10	$ 30,160.98
Jan 2020	$ 3,192.44	0.02%	31	$ 202.54	$ 3,394.98	$ 32,439.32	$ 1,116.64	$ 33,555.96
Feb 2020	$ 2,986.47	0.02%	29	$ 207.59	$ 3,194.06	$ 35,425.79	$ 1,324.23	$ 36,750.02
Mar 2020	$ 3,192.44	0.02%	31	$ 242.55	$ 3,434.99	$ 38,618.23	$ 1,566.78	$ 40,185.01
Apr 2020	$ 3,089.46	0.02%	30	$ 254.31	$ 3,343.77	$ 41,707.69	$ 1,821.09	$ 43,528.78
May 2020	$ 3,192.44	0.02%	31	$ 283.72	$ 3,476.16	$ 44,900.13	$ 2,104.81	$ 47,004.94
Jun 2020	$ 3,089.46	0.02%	30	$ 294.39	$ 3,383.85	$ 47,989.59	$ 2,399.20	$ 50,388.79
Jul 2020	$ 3,192.44	0.02%	31	$ 325.38	$ 3,517.82	$ 51,182.03	$ 2,724.58	$ 53,906.61
Aug 2020	$ 3,192.44	0.02%	31	$ 346.74	$ 3,539.18	$ 54,374.47	$ 3,071.32	$ 57,445.79
Sep 2020	$ 3,089.46	0.02%	30	$ 355.75	$ 3,445.21	$ 57,463.93	$ 3,427.07	$ 60,891.00
Oct 2020	$ 3,192.44	0.02%	31	$ 389.15	$ 3,581.59	$ 60,656.37	$ 3,816.22	$ 64,472.59
Nov 2020	$ 3,089.46	0.02%	30	$ 397.04	$ 3,486.50	$ 63,745.83	$ 4,213.26	$ 67,959.09
Dec 2020	$ 3,192.44	0.02%	31	$ 432.07	$ 3,624.51	$ 66,938.27	$ 4,645.33	$ 71,583.60
Jan 2021	$ 3,192.44	0.02%	31	$ 454.09	$ 3,646.53	$ 70,130.71	$ 5,099.42	$ 75,230.13
Feb 2021	$ 2,883.49	0.02%	28	$ 428.45	$ 3,311.94	$ 73,014.20	$ 5,527.87	$ 78,542.07
Mar 2021	$ 3,192.44	0.02%	31	$ 496.34	$ 3,688.78	$ 76,206.64	$ 6,024.21	$ 82,230.85
Apr 2021	$ 3,089.46	0.02%	30	$ 501.40	$ 3,590.86	$ 79,296.10	$ 6,525.61	$ 85,821.71
May 2021	$ 3,192.44	0.02%	31	$ 540.55	$ 3,732.99	$ 82,488.54	$ 7,066.16	$ 89,554.70
Jun 2021	$ 3,089.46	0.02%	30	$ 544.44	$ 3,633.90	$ 85,578.00	$ 7,610.60	$ 93,188.60
Jul 2021	$ 3,192.44	0.02%	31	$ 585.28	$ 3,777.72	$ 88,770.44	$ 8,195.88	$ 96,966.32
Aug 2021	$ 3,192.44	0.02%	31	$ 608.22	$ 3,800.66	$ 91,962.88	$ 8,804.10	$ 100,766.98
Sep 2021	$ 3,089.46	0.02%	30	$ 610.33	$ 3,699.79	$ 95,052.34	$ 9,414.43	$ 104,466.77
Oct 2021	$ 3,192.44	0.02%	31	$ 653.77	$ 3,846.21	$ 98,244.78	$ 10,068.20	$ 108,312.98
Nov 2021	$ 3,069.55	0.02%	30	$ 654.56	$ 3,724.11	$ 101,314.33	$ 10,722.76	$ 112,037.09
Dec 2021	$ 3,171.87	0.02%	31	$ 699.62	$ 3,871.49	$ 104,486.20	$ 11,422.38	$ 115,908.58
Jan 2022	$ 3,171.87	0.02%	31	$ 723.13	$ 3,895.00	$ 107,658.07	$ 12,145.51	$ 119,803.58
Feb 2022	$ 2,864.92	0.02%	28	$ 672.83	$ 3,537.75	$ 110,522.99	$ 12,818.34	$ 123,341.33
Mar 2022	$ 3,171.87	0.02%	31	$ 768.26	$ 3,940.13	$ 113,694.86	$ 13,586.60	$ 127,281.46
Apr 2022	$ 3,069.55	0.02%	30	$ 766.04	$ 3,835.59	$ 116,764.41	$ 14,352.64	$ 131,117.05
May 2022	$ 3,171.87	0.02%	31	$ 815.48	$ 3,987.35	$ 119,936.28	$ 15,168.12	$ 135,104.40
Jun 2022	$ 3,069.55	0.02%	30	$ 812.01	$ 3,881.56	$ 123,005.83	$ 15,980.13	$ 138,985.96
Jul 2022	$ 3,171.87	0.02%	31	$ 863.27	$ 4,035.14	$ 126,177.70	$ 16,843.40	$ 143,021.10
Aug 2022	$ 3,171.87	0.02%	31	$ 887.77	$ 4,059.64	$ 129,349.57	$ 17,731.17	$ 147,080.74
Sep 2022	$ 3,069.55	0.02%	30	$ 882.39	$ 3,951.94	$ 132,419.12	$ 18,613.56	$ 151,032.68
Oct 2022	$ 3,171.87	0.02%	31	$ 936.42	$ 4,108.29	$ 135,590.99	$ 19,549.98	$ 155,140.97
Nov 2022	$ 3,069.55	0.02%	30	$ 929.76	$ 3,999.31	$ 138,660.54	$ 20,479.74	$ 159,140.28
Dec 2022	$ 3,171.87	0.02%	31	$ 985.66	$ 4,157.53	$ 141,832.41	$ 21,465.40	$ 163,297.81
Jan 2023	$ 3,171.87	0.02%	31	$ 1,010.90	$ 4,182.77	$ 145,004.28	$ 22,476.30	$ 167,480.58
Feb 2023	$ 2,864.92	0.02%	28	$ 934.33	$ 3,799.25	$ 147,869.20	$ 23,410.63	$ 171,279.83
Mar 2023	$ 3,171.87	0.02%	31	$ 1,059.38	$ 4,231.25	$ 151,041.07	$ 24,470.01	$ 175,511.08
Apr 2023	$ 3,069.55	0.02%	30	$ 1,049.47	$ 4,119.02	$ 154,110.62	$ 25,519.48	$ 179,630.10
May 2023	$ 3,171.87	0.02%	31	$ 1,110.08	$ 4,281.95	$ 157,282.49	$ 26,629.56	$ 183,912.05
Jun 2023	$ 3,069.55	0.02%	30	$ 1,098.84	$ 4,168.39	$ 160,352.04	$ 27,728.40	$ 188,080.44
Jul 2023	$ 3,171.87	0.02%	31	$ 1,161.40	$ 4,333.27	$ 163,523.91	$ 28,889.80	$ 192,413.71
Aug 2023	$ 3,171.87	0.02%	31	$ 1,187.71	$ 4,359.58	$ 166,695.78	$ 30,077.51	$ 196,773.29
Sep 2023	$ 3,069.55	0.02%	30	$ 1,174.42	$ 4,243.97	$ 169,765.33	$ 31,251.93	$ 201,017.26
Oct 1-18, 2023	$ 1,841.73	0.02%	18	$ 715.29	$ 2,557.02	$ 171,607.06	$ 31,967.22	$ 203,574.28
Oct 19-31, 2023	$ -	0.02%	13	$ 546.69	$ 546.69	$ 171,607.06	$ 32,513.91	$ 204,120.97
Nov 2023	$ -	0.02%	30	$ 1,264.99	$ 1,264.99	$ 171,607.06	$ 33,778.90	$ 205,385.96
Dec 2023	$ -	0.02%	31	$ 1,315.26	$ 1,315.26	$ 171,607.06	$ 35,094.16	$ 206,701.22
Jan 2024	$ -	0.02%	15.5	$ 661.84	$ 661.84	$ 171,607.06	$ 35,756.00	$ 207,363.06
Total	$ 171,607.06			$ 35,756.00	$ 207,363.06			

Principal and Carrying Charge Calculation
Sponsorship/Advertising

	Sponsorship / Advertising
Effective March 23, 2019	
O&M Revenue Req	$ 194,146.39
Capital Revenue Req	1,792.19
	$ 195,938.58
Effective November 1, 2021	
O&M Revenue Req	$ 194,146.39
Capital Revenue Req	1,684.92
	$ 195,831.31

PSC Ordered ROR	7.15%	thru Oct 18, 2023
Proposed ROR	7.54%	after Oct 18, 2023

	Total Before Carrying Charge	ROR Daily Carrying Charge %	Days in Month	Compounded Carrying Charge	Total with Carrying Charge	Cumulative Principal	Cumulative Carrying Charge	Cumulative Principal + Carrying Charge
Mar 23-31, 2019	$ 4,831.36	0.02%	9	$ 8.52	$ 4,839.88	$ 4,831.36	$ 8.52	$ 4,839.88
Apr 2019	$ 16,104.54	0.02%	30	$ 123.08	$ 16,227.62	$ 20,935.90	$ 131.60	$ 21,067.50
May 2019	$ 16,641.36	0.02%	31	$ 228.99	$ 16,870.35	$ 37,577.26	$ 360.59	$ 37,937.85
Jun 2019	$ 16,104.54	0.02%	30	$ 317.59	$ 16,422.13	$ 53,681.80	$ 678.18	$ 54,359.98
Jul 2019	$ 16,641.36	0.02%	31	$ 431.16	$ 17,072.52	$ 70,323.16	$ 1,109.34	$ 71,432.50
Aug 2019	$ 16,641.36	0.02%	31	$ 534.84	$ 17,176.20	$ 86,964.52	$ 1,644.18	$ 88,608.70
Sep 2019	$ 16,104.54	0.02%	30	$ 615.37	$ 16,719.91	$ 103,069.06	$ 2,259.55	$ 105,328.61
Oct 2019	$ 16,641.36	0.02%	31	$ 740.68	$ 17,382.04	$ 119,710.42	$ 3,000.23	$ 122,710.65
Nov 2019	$ 16,104.54	0.02%	30	$ 815.78	$ 16,920.32	$ 135,814.96	$ 3,816.01	$ 139,630.97
Dec 2019	$ 16,641.36	0.02%	31	$ 948.98	$ 17,590.34	$ 152,456.32	$ 4,764.99	$ 157,221.31
Jan 2020	$ 16,641.36	0.02%	31	$ 1,055.80	$ 17,697.16	$ 169,097.68	$ 5,820.79	$ 174,918.47
Feb 2020	$ 15,567.72	0.02%	29	$ 1,082.12	$ 16,649.84	$ 184,665.40	$ 6,902.91	$ 191,568.31
Mar 2020	$ 16,641.36	0.02%	31	$ 1,264.37	$ 17,905.73	$ 201,306.76	$ 8,167.28	$ 209,474.04
Apr 2020	$ 16,104.54	0.02%	30	$ 1,325.66	$ 17,430.20	$ 217,411.30	$ 9,492.94	$ 226,904.24
May 2020	$ 16,641.36	0.02%	31	$ 1,478.96	$ 18,120.32	$ 234,052.66	$ 10,971.90	$ 245,024.56
Jun 2020	$ 16,104.54	0.02%	30	$ 1,534.58	$ 17,639.12	$ 250,157.20	$ 12,506.48	$ 262,663.68
Jul 2020	$ 16,641.36	0.02%	31	$ 1,696.11	$ 18,337.47	$ 266,798.56	$ 14,202.59	$ 281,001.15
Aug 2020	$ 16,641.36	0.02%	31	$ 1,807.46	$ 18,448.82	$ 283,439.92	$ 16,010.05	$ 299,449.97
Sep 2020	$ 16,104.54	0.02%	30	$ 1,854.42	$ 17,958.96	$ 299,544.46	$ 17,864.47	$ 317,408.93
Oct 2020	$ 16,641.36	0.02%	31	$ 2,028.55	$ 18,669.91	$ 316,185.82	$ 19,893.02	$ 336,078.84
Nov 2020	$ 16,104.54	0.02%	30	$ 2,069.68	$ 18,174.22	$ 332,290.36	$ 21,962.70	$ 354,253.06
Dec 2020	$ 16,641.36	0.02%	31	$ 2,252.29	$ 18,893.65	$ 348,931.72	$ 24,214.99	$ 373,146.71
Jan 2021	$ 16,641.36	0.02%	31	$ 2,367.03	$ 19,008.39	$ 365,573.08	$ 26,582.02	$ 392,155.10
Feb 2021	$ 15,030.90	0.02%	28	$ 2,233.39	$ 17,264.29	$ 380,603.98	$ 28,815.41	$ 409,419.39
Mar 2021	$ 16,641.36	0.02%	31	$ 2,587.30	$ 19,228.66	$ 397,245.34	$ 31,402.71	$ 428,648.05
Apr 2021	$ 16,104.54	0.02%	30	$ 2,613.68	$ 18,718.22	$ 413,349.88	$ 34,016.39	$ 447,366.27
May 2021	$ 16,641.36	0.02%	31	$ 2,817.73	$ 19,459.09	$ 429,991.24	$ 36,834.12	$ 466,825.36
Jun 2021	$ 16,104.54	0.02%	30	$ 2,838.04	$ 18,942.58	$ 446,095.78	$ 39,672.16	$ 485,767.94
Jul 2021	$ 16,641.36	0.02%	31	$ 3,050.93	$ 19,692.29	$ 462,737.14	$ 42,723.09	$ 505,460.23
Aug 2021	$ 16,641.36	0.02%	31	$ 3,170.52	$ 19,811.88	$ 479,378.50	$ 45,893.61	$ 525,272.11
Sep 2021	$ 16,104.54	0.02%	30	$ 3,181.51	$ 19,286.05	$ 495,483.04	$ 49,075.12	$ 544,558.16
Oct 2021	$ 16,641.36	0.02%	31	$ 3,407.94	$ 20,049.30	$ 512,124.40	$ 52,483.06	$ 564,607.46
Nov 2021	$ 16,095.72	0.02%	30	$ 3,412.63	$ 19,508.35	$ 528,220.12	$ 55,895.69	$ 584,115.81
Dec 2021	$ 16,632.25	0.02%	31	$ 3,648.10	$ 20,280.35	$ 544,852.37	$ 59,543.79	$ 604,396.16
Jan 2022	$ 16,632.25	0.02%	31	$ 3,771.26	$ 20,403.51	$ 561,484.62	$ 63,315.05	$ 624,799.67
Feb 2022	$ 15,022.68	0.02%	28	$ 3,509.38	$ 18,532.06	$ 576,507.30	$ 66,824.43	$ 643,331.73
Mar 2022	$ 16,632.25	0.02%	31	$ 4,007.70	$ 20,639.95	$ 593,139.55	$ 70,832.13	$ 663,971.68
Apr 2022	$ 16,095.72	0.02%	30	$ 3,996.56	$ 20,092.28	$ 609,235.27	$ 74,828.69	$ 684,063.96
May 2022	$ 16,632.25	0.02%	31	$ 4,255.05	$ 20,887.30	$ 625,867.52	$ 79,083.74	$ 704,951.26
Jun 2022	$ 16,095.72	0.02%	30	$ 4,237.39	$ 20,333.11	$ 641,963.24	$ 83,321.13	$ 725,284.37
Jul 2022	$ 16,632.25	0.02%	31	$ 4,505.36	$ 21,137.61	$ 658,595.49	$ 87,826.49	$ 746,421.98
Aug 2022	$ 16,632.25	0.02%	31	$ 4,633.73	$ 21,265.98	$ 675,227.74	$ 92,460.22	$ 767,687.96
Sep 2022	$ 16,095.72	0.02%	30	$ 4,606.07	$ 20,701.79	$ 691,323.46	$ 97,066.29	$ 788,389.75
Oct 2022	$ 16,632.25	0.02%	31	$ 4,888.58	$ 21,520.83	$ 707,955.71	$ 101,954.87	$ 809,910.58
Nov 2022	$ 16,095.72	0.02%	30	$ 4,854.20	$ 20,949.92	$ 724,051.43	$ 106,809.07	$ 830,860.50
Dec 2022	$ 16,632.25	0.02%	31	$ 5,146.49	$ 21,778.74	$ 740,683.68	$ 111,955.56	$ 852,639.24
Jan 2023	$ 16,632.25	0.02%	31	$ 5,278.74	$ 21,910.99	$ 757,315.93	$ 117,234.30	$ 874,550.23
Feb 2023	$ 15,022.68	0.02%	28	$ 4,879.25	$ 19,901.93	$ 772,338.61	$ 122,113.55	$ 894,452.16
Mar 2023	$ 16,632.25	0.02%	31	$ 5,532.65	$ 22,164.90	$ 788,970.86	$ 127,646.20	$ 916,617.06
Apr 2023	$ 16,095.72	0.02%	30	$ 5,481.28	$ 21,577.00	$ 805,066.58	$ 133,127.48	$ 938,194.06
May 2023	$ 16,632.25	0.02%	31	$ 5,798.28	$ 22,430.53	$ 821,698.83	$ 138,925.76	$ 960,624.59
Jun 2023	$ 16,095.72	0.02%	30	$ 5,739.90	$ 21,835.62	$ 837,794.55	$ 144,665.66	$ 982,460.21
Jul 2023	$ 16,632.25	0.02%	31	$ 6,067.09	$ 22,699.34	$ 854,426.80	$ 150,732.75	$ 1,005,159.55
Aug 2023	$ 16,632.25	0.02%	31	$ 6,204.94	$ 22,837.19	$ 871,059.05	$ 156,937.69	$ 1,027,996.74
Sep 2023	$ 16,095.72	0.02%	30	$ 6,135.83	$ 22,231.55	$ 887,154.77	$ 163,073.52	$ 1,050,228.29
Oct 1-18, 2023	$ 9,657.43	0.02%	18	$ 3,737.19	$ 13,394.62	$ 896,812.20	$ 166,810.71	$ 1,063,622.91
Oct 19-31, 2023	$ -	0.02%	13	$ 2,856.34	$ 2,856.34	$ 896,812.20	$ 169,667.05	$ 1,066,479.25
Nov 2023	$ -	0.02%	30	$ 6,609.25	$ 6,609.25	$ 896,812.20	$ 176,276.30	$ 1,073,088.50
Dec 2023	$ -	0.02%	31	$ 6,871.88	$ 6,871.88	$ 896,812.20	$ 183,148.18	$ 1,079,960.38
Jan 2024	$ -	0.02%	15.5	$ 3,457.94	$ 3,457.94	$ 896,812.20	$ 186,606.12	$ 1,083,418.32
Total	$ 896,812.20			$ 186,606.12	$ 1,083,418.32			

THE POTOMAC EDISON COMPANY - MARYLAND

Principal and Carrying Charge Calculation

Miscellaneous

		Miscellaneous
Effective March 23, 2019		
O&M Revenue Req	$	62,675.89
Capital Revenue Req		5,745.02
	$	68,420.91
Effective November 1, 2021		
O&M Revenue Req	$	62,675.89
Capital Revenue Req		5,401.64
	$	68,077.53

PSC Ordered ROR	7.15%	thru Oct 18, 2023
Proposed ROR	7.54%	after Oct 18, 2023

	Total Before Carrying Charge	ROR Daily Carrying Charge %	Days in Month	Compounded Carrying Charge	Total with Carrying Charge	Cumulative Principal	Cumulative Carrying Charge	Cumulative Principal + Carrying Charge
Mar 23-31, 2019	$ 1,687.09	0.02%	9	$ 2.97	$ 1,690.06	$ 1,687.09	$ 2.97	$ 1,690.06
Apr 2019	$ 5,623.64	0.02%	30	$ 42.98	$ 5,666.62	$ 7,310.73	$ 45.95	$ 7,356.68
May 2019	$ 5,811.09	0.02%	31	$ 79.96	$ 5,891.05	$ 13,121.82	$ 125.91	$ 13,247.73
Jun 2019	$ 5,623.64	0.02%	30	$ 110.90	$ 5,734.54	$ 18,745.46	$ 236.81	$ 18,982.27
Jul 2019	$ 5,811.09	0.02%	31	$ 150.56	$ 5,961.65	$ 24,556.55	$ 387.37	$ 24,943.92
Aug 2019	$ 5,811.09	0.02%	31	$ 186.76	$ 5,997.85	$ 30,367.64	$ 574.13	$ 30,941.77
Sep 2019	$ 5,623.64	0.02%	30	$ 214.88	$ 5,838.52	$ 35,991.28	$ 789.01	$ 36,780.29
Oct 2019	$ 5,811.09	0.02%	31	$ 258.64	$ 6,069.73	$ 41,802.37	$ 1,047.65	$ 42,850.02
Nov 2019	$ 5,623.64	0.02%	30	$ 284.87	$ 5,908.51	$ 47,426.01	$ 1,332.52	$ 48,758.53
Dec 2019	$ 5,811.09	0.02%	31	$ 331.38	$ 6,142.47	$ 53,237.10	$ 1,663.90	$ 54,901.00
Jan 2020	$ 5,811.09	0.02%	31	$ 368.68	$ 6,179.77	$ 59,048.19	$ 2,032.58	$ 61,080.77
Feb 2020	$ 5,436.18	0.02%	29	$ 377.87	$ 5,814.05	$ 64,484.37	$ 2,410.45	$ 66,894.82
Mar 2020	$ 5,811.09	0.02%	31	$ 441.51	$ 6,252.60	$ 70,295.46	$ 2,851.96	$ 73,147.42
Apr 2020	$ 5,623.64	0.02%	30	$ 462.91	$ 6,086.55	$ 75,919.10	$ 3,314.87	$ 79,233.97
May 2020	$ 5,811.09	0.02%	31	$ 516.44	$ 6,327.53	$ 81,730.19	$ 3,831.31	$ 85,561.50
Jun 2020	$ 5,623.64	0.02%	30	$ 535.87	$ 6,159.51	$ 87,353.83	$ 4,367.18	$ 91,721.01
Jul 2020	$ 5,811.09	0.02%	31	$ 592.27	$ 6,403.36	$ 93,164.92	$ 4,959.45	$ 98,124.37
Aug 2020	$ 5,811.09	0.02%	31	$ 631.16	$ 6,442.25	$ 98,976.01	$ 5,590.61	$ 104,566.62
Sep 2020	$ 5,623.64	0.02%	30	$ 647.56	$ 6,271.20	$ 104,599.65	$ 6,238.17	$ 110,837.82
Oct 2020	$ 5,811.09	0.02%	31	$ 708.36	$ 6,519.45	$ 110,410.74	$ 6,946.53	$ 117,357.27
Nov 2020	$ 5,623.64	0.02%	30	$ 722.72	$ 6,346.36	$ 116,034.38	$ 7,669.25	$ 123,703.63
Dec 2020	$ 5,811.09	0.02%	31	$ 786.49	$ 6,597.58	$ 121,845.47	$ 8,455.74	$ 130,301.21
Jan 2021	$ 5,811.09	0.02%	31	$ 826.56	$ 6,637.65	$ 127,656.56	$ 9,282.30	$ 136,938.86
Feb 2021	$ 5,248.73	0.02%	28	$ 779.89	$ 6,028.62	$ 132,905.29	$ 10,062.19	$ 142,967.48
Mar 2021	$ 5,811.09	0.02%	31	$ 903.47	$ 6,714.56	$ 138,716.38	$ 10,965.66	$ 149,682.04
Apr 2021	$ 5,623.64	0.02%	30	$ 912.69	$ 6,536.33	$ 144,340.02	$ 11,878.35	$ 156,218.37
May 2021	$ 5,811.09	0.02%	31	$ 983.94	$ 6,795.03	$ 150,151.11	$ 12,862.29	$ 163,013.40
Jun 2021	$ 5,623.64	0.02%	30	$ 991.03	$ 6,614.67	$ 155,774.75	$ 13,853.32	$ 169,628.07
Jul 2021	$ 5,811.09	0.02%	31	$ 1,065.37	$ 6,876.46	$ 161,585.84	$ 14,918.69	$ 176,504.53
Aug 2021	$ 5,811.09	0.02%	31	$ 1,107.13	$ 6,918.22	$ 167,396.93	$ 16,025.82	$ 183,422.75
Sep 2021	$ 5,623.64	0.02%	30	$ 1,110.97	$ 6,734.61	$ 173,020.57	$ 17,136.79	$ 190,157.36
Oct 2021	$ 5,811.09	0.02%	31	$ 1,190.04	$ 7,001.13	$ 178,831.66	$ 18,326.83	$ 197,158.49
Nov 2021	$ 5,595.41	0.02%	30	$ 1,191.53	$ 6,786.94	$ 184,427.07	$ 19,518.36	$ 203,945.43
Dec 2021	$ 5,781.93	0.02%	31	$ 1,273.59	$ 7,055.52	$ 190,209.00	$ 20,791.95	$ 211,000.95
Jan 2022	$ 5,781.93	0.02%	31	$ 1,316.44	$ 7,098.37	$ 195,990.93	$ 22,108.39	$ 218,099.32
Feb 2022	$ 5,222.39	0.02%	28	$ 1,224.90	$ 6,447.29	$ 201,213.32	$ 23,333.29	$ 224,546.61
Mar 2022	$ 5,781.93	0.02%	31	$ 1,398.69	$ 7,180.62	$ 206,995.25	$ 24,731.98	$ 231,727.23
Apr 2022	$ 5,595.41	0.02%	30	$ 1,394.68	$ 6,990.09	$ 212,590.66	$ 26,126.66	$ 238,717.32
May 2022	$ 5,781.93	0.02%	31	$ 1,484.75	$ 7,266.68	$ 218,372.59	$ 27,611.41	$ 245,984.00
Jun 2022	$ 5,595.41	0.02%	30	$ 1,478.46	$ 7,073.87	$ 223,968.00	$ 29,089.87	$ 253,057.87
Jul 2022	$ 5,781.93	0.02%	31	$ 1,571.83	$ 7,353.76	$ 229,749.93	$ 30,661.70	$ 260,411.63
Aug 2022	$ 5,781.93	0.02%	31	$ 1,616.49	$ 7,398.42	$ 235,531.86	$ 32,278.19	$ 267,810.05
Sep 2022	$ 5,595.41	0.02%	30	$ 1,606.73	$ 7,202.14	$ 241,127.27	$ 33,884.92	$ 275,012.19
Oct 2022	$ 5,781.93	0.02%	31	$ 1,705.15	$ 7,487.08	$ 246,909.20	$ 35,590.07	$ 282,499.27
Nov 2022	$ 5,595.41	0.02%	30	$ 1,693.05	$ 7,288.46	$ 252,504.61	$ 37,283.12	$ 289,787.73
Dec 2022	$ 5,781.93	0.02%	31	$ 1,794.88	$ 7,576.81	$ 258,286.54	$ 39,078.00	$ 297,364.54
Jan 2023	$ 5,781.93	0.02%	31	$ 1,840.89	$ 7,622.82	$ 264,068.47	$ 40,918.89	$ 304,987.36
Feb 2023	$ 5,222.39	0.02%	28	$ 1,701.48	$ 6,923.87	$ 269,290.86	$ 42,620.37	$ 311,911.23
Mar 2023	$ 5,781.93	0.02%	31	$ 1,929.22	$ 7,711.15	$ 275,072.79	$ 44,549.59	$ 319,622.38
Apr 2023	$ 5,595.41	0.02%	30	$ 1,911.21	$ 7,506.62	$ 280,668.20	$ 46,460.80	$ 327,129.00
May 2023	$ 5,781.93	0.02%	31	$ 2,021.64	$ 7,803.57	$ 286,450.13	$ 48,482.44	$ 334,932.57
Jun 2023	$ 5,595.41	0.02%	30	$ 2,001.18	$ 7,596.59	$ 292,045.54	$ 50,483.62	$ 342,529.16
Jul 2023	$ 5,781.93	0.02%	31	$ 2,115.15	$ 7,897.08	$ 297,827.47	$ 52,598.77	$ 350,426.24
Aug 2023	$ 5,781.93	0.02%	31	$ 2,163.11	$ 7,945.04	$ 303,609.40	$ 54,761.88	$ 358,371.28
Sep 2023	$ 5,595.41	0.02%	30	$ 2,138.93	$ 7,734.34	$ 309,204.81	$ 56,900.81	$ 366,105.62
Oct 1-18, 2023	$ 3,357.25	0.02%	18	$ 1,302.74	$ 4,659.99	$ 312,562.06	$ 58,203.55	$ 370,765.61
Oct 19-31, 2023	$ -	0.02%	13	$ 995.68	$ 995.68	$ 312,562.06	$ 59,199.23	$ 371,761.29
Nov 2023	$ -	0.02%	30	$ 2,303.90	$ 2,303.90	$ 312,562.06	$ 61,503.13	$ 374,065.19
Dec 2023	$ -	0.02%	31	$ 2,395.45	$ 2,395.45	$ 312,562.06	$ 63,898.58	$ 376,460.64
Jan 2024	$ -	0.02%	15.5	$ 1,205.40	$ 1,205.40	$ 312,562.06	$ 65,103.98	$ 377,666.04
Total	$ 312,562.06			$ 65,103.98	$ 377,666.04			

THE POTOMAC EDISON COMPANY - MARYLAND
Illustrative Customer Refund Calculation

Schedule	2019 Distribution[1] Revenue	2019 Distribution[1] %-to-Total	Regulatory Liability with Interest	January 2024 Forecast[2] Customers	January 2024 Forecast[2] kWh	Estimated January 2024[2] Credit/Cust	Estimated January 2024[2] Credit/kWh
R	$ 73,832,904	62.4%	$ (1,041,572)	256,466		$ (4.06)	
G	$ 19,374,083	16.4%	$ (273,313)	27,759		$ (9.85)	
C	$ 2,940,608	2.5%	$ (41,484)	3,924		$ (10.57)	
C-A & CSH	$ 471,049	0.4%	$ (6,645)	324		$ (20.51)	
PH	$ 15,586,131	13.2%	$ (219,876)	1,747		$ (125.86)	
AGS	$ 7,283	0.0%	$ (103)	1		$ (102.74)	
PP	$ 1,178,518	1.0%	$ (16,626)		see below	see below	
Hag & Fred	$ 21,747	0.0%	$ (307)		107,950		$ (0.00284)
Street Lighting	$ 4,857,261	4.1%	$ (68,522)		2,174,073		$ (0.03152)
Total	$ 118,269,584	100.0%	$ (1,668,447)				

Schedule PP Customer	Estimated Jan '24 Credit/Customer[3]
1	$ (1,245.62)
2	$ (711.85)
3	$ (1,790.14)
4	$ (626.39)
5	$ (516.25)
6	$ (3,507.14)
7	$ (6,766.71)
8	$ (308.55)
9	$ (958.95)
10	$ (193.95)
Total	$ (16,625.54)

[1]Per Potomac Edison Tariff Compliance filing dated March 25, 2019 in Case No. 9490 (Maillog #224435)

[2]Forecast to be updated for November 2023 filing for credits effective during January 2024

[3]Schedule PP credits allocated from billed kWh for 12 months ended September 2023; currently based upon forecasted kWh which will be updated with actual kWh during November 2023 filing for credits effective during January 2024

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

STEPHANIE L. FALL

Concerning: Retail Tariff Revisions and EDIS Phase II Cost Impacts

March 22, 2023

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephanie L. Fall, and my business address is 76 South Main Street, Akron, Ohio, 44308.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by FirstEnergy Service Company as a Manager in the Rates and Regulatory Affairs Department – West Virginia/Maryland. I report to the Director, Rates and Regulatory Affairs, and my responsibilities include overseeing the development, coordination, preparation and presentation of retail tariffs, and the development of retail electric rates, rules, and regulations in the retail tariff. My time is devoted to tasks performed for The Potomac Edison Company ("PE or "Company") and Monongahela Power Company ("Mon Power").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I am a graduate of Ohio University where I earned a Bachelor of Business Administration in Accounting, Finance and Business Pre-Law. I have over 17 years of experience with FirstEnergy Service Company or its predecessor companies, and have held positions of Business Analyst, FES Finance; Fuel Specialist, Fuel Procurement; Analyst, Renewables; Analyst, Rates Support; Analyst, Investor Relations; Analyst, Strategy and my current position of Manager, Rates and Regulatory Affairs.

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

A. My testimony will address the following:

1. Proposed retail tariff revisions; and
2. The cost impacts of the proposed Electric Distribution Investment Surcharge ("EDIS") Phase II.

Q. HAVE YOU PREPARED OR HAD PREPARED UNDER YOUR SUPERVISION EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibits, which will be discussed further in my testimony:

Exhibit SLF-1: Clean version of the retail tariff

Exhibit SLF-2: Redlined version of the retail tariff

Exhibit SLF-3: 2024 EDIS calculation

II. RETAIL TARIFF REVISIONS

Q. HAVE YOU PREPARED REVISIONS TO THE RETAIL TARIFF TO REFLECT THE COMPANY'S PROPOSED NEW DISTRIBUTION RATES?

A. Yes, Exhibit SLF-1 contains the new distribution rates for each affected rate schedule based upon the proposed distribution rates contained in the exhibits of Company witness Lyons plus the rate increment for the new low-income assistance programs discussed by Company witnesses Valdes and Larnerd.

Q. ARE THERE ANY ADDITIONAL TARIFF UPDATES PROPOSED IN THIS PROCEEDING?

A. Yes. In addition to the proposed rate changes previously discussed, the Company proposes minor updates and clarifications to certain provisions and rules in the retail tariff. Given that only four years have passed since PE's last distribution base rate case, with all outdated legacy items being removed from the retail tariff upon conclusion of that prior rate case, there are not a large amount of additional updates proposed in this proceeding. The proposed tariff changes affect Schedules PH, PP, CO-G, SP and LED, and are generally informative in nature or add additional clarity that is not present in the current version of those rate schedules.

Q. HAS A REDLINED VERSION OF THE TARIFF CHANGES BEEN PREPARED?

A. Yes. Exhibit SLF-2 contains a redlined version of the Company's retail tariff so that all proposed changes can easily be identified. Only affected tariff pages are included, meaning that tariff pages that have no proposed changes are not included in Exhibits SLF-1 or SLF-2.

Q. PLEASE PROVIDE A DESCRIPTION OF SCHEDULES PH AND PP AND AN EXPLANATION OF THE PROPOSED CHANGES.

A. Schedule PH is a commercial and industrial rate schedule for mid-size customers and is available to customers with demands of 50 kilowatts ("kW") or greater. Schedule PP is a commercial and industrial rate schedule for large-size customers and is available to customers with demands of 5,000 kW or greater that are also served from high-voltage[1] service facilities. Both rate schedules currently list the kW eligibility levels of 50 kW and

[1] High-voltage service is typically 34,500 volts or higher but can be as low as 12,470 volts in certain situations.

5,000 kW for Schedules PH and PP, respectively, but do not clarify the frequency by which such kW levels are to be achieved. The Availability section of both rate schedules is updated to include language that clarifies customer load must equal or exceed 50 kW and 5,000 kW for Schedules PH and PP, respectively, at least once during a rolling 12-month period to maintain eligibility for the respective rate schedules.

Q. PLEASE PROVIDE A DESCRIPTION OF SCHEDULE CO-G AND AN EXPLANATION OF THE PROPOSED CHANGES.

A. Schedule CO-G is a rate schedule available for the purchase of electricity by the Company from co-generators and small power producers. On October 13, 2021, FirstEnergy Service Company, as agent for the FirstEnergy utility companies including PE, submitted an application pursuant to section 210(m) of the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the applicable Federal Energy Regulatory Commission ("FERC") regulations to terminate the requirement to enter into new contracts or obligations to purchase electric energy and capacity from any qualifying facility ("QF") within PJM Interconnection, L.L.C. ("PJM") with a net capacity greater than 20 megawatts ("MW"), and any small power production QF with a net capacity greater than 5 MW on a service territory-wide basis. The FERC issued an Order[2] approving the application on December 17, 2021 making the request effective October 13, 2021.

The kW change on Schedule CO-G is made to make eligibility consistent with the FERC Order on PURPA obligation requirements. Additional changes on energy and

[2] FERC Order issued in Docket Number QM22-4-000.

capacity payments within Schedule CO-G are to address project applications that PE may receive for qualifying PURPA interconnection at the distribution level and outside of the PJM market. The changes under Sales to Qualifying Facilities and Interconnection Costs are for clarification purposes.

Q. PLEASE PROVIDE A DESCRIPTION OF SCHEDULE SP AND AN EXPLANATION OF THE PROPOSED CHANGES.

A. Schedule SP is a rate schedule that covers rare situations where a generation station within PJM and the Company's service territory is not generating for an entire PJM billing period. The changes on this schedule clarify the applicable charges customers will be billed based upon whether they are a net producer or consumer of generation.

Q. PLEASE PROVIDE A DESCRIPTION OF SCHEDULE LED AND AN EXPLANATION OF THE PROPOSED CHANGES.

A. Schedule LED is a rate schedule for the provision of street lighting service from light emitting diode ("LED") street lights. PE wanted to remove potential barriers for customers to switch to Schedule LED, therefore it has removed the eligibility restriction for group installation of 12 or more LED street lights.

PE is also inserting language to provide customers with an option to negotiate a contract for service on an individual basis. These contracts may include additional terms and conditions regarding advanced functionality of the LED street lights. Inserting this language expands the options for customers who wish to move to connected LED street lighting.

Q. IS THE COMPANY PROPOSING TO EXPAND ITS LED STREET LIGHTING SERVICE SCHEDULE?

A. Not in this proceeding, other than to make the two changes above which expand options for customers. However, PE is currently assessing ways to provide customers additional opportunities to transition to LED street lighting. At this time, the Company is evaluating available LED street light offerings and is determining the path to potentially expand Schedule LED in a future filing.

Q. DO YOU PLAN TO CLOSE ANY STREET LIGHTING SCHEDULES IN CONJUNCTION WITH THE POTENTIAL EXPANSION OF THE LED STREET LIGHTING SERVICE SCHEDULE?

A. Yes, concurrent with the possible future filing I mention above. Due to limited availability of non-LED street lighting fixtures, the Company plans to review the current street lighting rate schedules that are not restricted to new customers and/or installations and will propose to close those schedules (or specific street lights) to new customers and installations when equivalent LED street lighting options are available in conjunction with an expanded Schedule LED. This will ensure customers have comparable options on Schedule LED to replace their existing street lighting. Customers that do not switch to Schedule LED may remain on their current street lighting rate schedule until they voluntarily choose to discontinue street lighting service or if switching to LED street lights must occur due to non-availability of non-LED replacements.

III. EDIS PHASE II

Q. IS THE COMPANY PROPOSING CONTINUATION OF INCREMENTAL ELECTRIC DISTRIBUTION INVESTMENTS?

A. Yes. Company witness McGettigan discusses the historical reliability performance of the Company that includes the effects of the current EDIS programs, and then he describes proposed incremental investments and program enhancements as part of EDIS Phase II to help improve reliability to customers. These proposed investments and enhancements are as follows:

1. Underground Cable Replacement program;
2. Substation Recloser Replacement program; and
3. Resiliency program, which includes the previously-approved distribution automation program.

Q. ARE ANY EDIS COSTS BEING ROLLED INTO DISTRIBUTION RATES AS PART OF THIS PROCEEDING?

A. Yes. In Order No. 89072 issued March 22, 2019 in Case No. 9490, the Maryland Public Service Commission ("Commission") authorized the Company to implement the underground cable replacement, substation recloser replacement, and distribution automation EDIS programs and to recover their costs through a surcharge mechanism through the end of December 2022. On April 28, 2022, the Company proposed and subsequently received Commission approval for a one-year extension of the EDIS through

2023.[3] As indicated in the Company's April 28, 2022 filing and per the Commission's order in the Company's prior distribution rate case, as part of this proceeding the Company is rolling into distribution rates all EDIS costs incurred through December 2022. Therefore, upon conclusion of this proceeding, the EDIS will be reduced to eliminate any costs incurred through December 2022. The EDIS will, instead, only reflect collection of costs incurred as of January 2023 as well as the proposed EDIS Phase II costs.

Q. DO THESE EDIS PHASE II INVESTMENTS AND ENHANCEMENTS RESULT IN ADDITIONAL COSTS?

A. Yes. The investments and enhancements involve incremental capital above and beyond costs that were incurred prior to original implementation of the EDIS and are all non-revenue-producing costs. As such, the incremental capital as of January 2023 is not in the rate case test year and is not reflected in the proposed distribution rates discussed in the testimony of Company witness Lyons. Since these are new and future costs that have yet to be incurred and are subject to Commission approval of the investments, the Company is proposing to continue surcharge recovery for these incremental costs. Continuation of the surcharge accomplishes three important objectives:

1. Allows for transparent and on-going Commission review of the surcharge and annual adjustments, so that customers pay no more than the actual costs for the actual projects completed;
2. Allows the surcharge to ultimately be based upon incremental actual costs

[3] Commission letter order dated June 15, 2022 (ML#s 240413 and 240434)

instead of incremental estimated costs, thereby adhering to a known and measurable standard; and

3. Mitigates the regulatory lag associated with traditional cost recovery through distribution rates, which would require the Company to install the investments in advance with uncertain approval by the Commission and the loss of cost recovery between the period of time the investments were made and distribution rates were reset.

Timely cost recovery of these incremental investments is part and parcel of the Company's proposal for the incremental EDIS Phase II investments.

Q. WHAT ARE THE FORECASTED CAPITAL COSTS FOR EDIS PHASE II?

A. Shown below in Table 1 is a forecast of the annual capital costs for each of the EDIS Phase II programs that were developed by the Company's Engineering Services department. As discussed later in my testimony, these estimates will be updated annually in a filing at the Commission for consideration and approval.

Table 1
Forecasted EDIS Phase II Capital Costs

	Underground Cable Replacement	Substation Recloser Replacement	Resiliency
2024	$18,838,900	$0	$2,800,000
2025	$20,335,550	$1,128,400	$2,800,000
2026	$21,832,200	$1,128,400	$2,800,000
2027	$23,439,000	$0	$2,800,000

Q. PLEASE DESCRIBE THE SURCHARGE.

A. The surcharge would continue to be identified as the EDIS and would recover the incremental investments associated with the previously-discussed EDIS Phase II categories of underground cable replacement, substation recloser replacement, and resiliency programs. All the cost categories reflect incremental capital costs and exclude operation and maintenance costs. The incremental costs represent an investment in the Company's infrastructure to the direct benefit of customers with a projected increase in reliability, as discussed by Company witness McGettigan. Cost recovery through the EDIS will consist of a revenue requirement for recovery of a return on and of incremental capital placed in-service. Upon conclusion of this rate proceeding, the return of capital will be calculated from Commission-approved depreciation rates, and the return on capital will be calculated in accordance with the Commission-approved capital structure, debt cost, and return on equity.[4]

Q. HOW IS THE EDIS REVENUE REQUIREMENT ALLOCATED TO COMPANY RATE SCHEDULES AND HOW ARE RATES CALCULATED?

A. Consistent with the Commission-approved allocation methodology of the current EDIS, the EDIS revenue requirement will be allocated to the various rate schedules based upon the non-coincident peak of each rate schedule, at both the primary and secondary levels based upon the split between primary and secondary distribution plant in the class cost of service study. To calculate the rate for each rate schedule, the allocated revenue requirement per rate schedule will be divided by its respective forecasted annual distribution kWh sales. Similar to the calculations contained in the class cost of service

[4] For purposes of my testimony and accompanying exhibits, the return on and of capital are at depreciation and rate of return rates proposed by the Company.

study, Schedules G and C will have identical EDIS rates, and Schedule C-A and the CSH subset will have identical EDIS rates.

The 2024 EDIS calculation is provided in Exhibit SLF-3. The 2024 EDIS rate would not be effective until the Company submits its annual reconciliation filing as described later in my testimony.

Q. WHAT IS THE EFFECT OF THE EDIS ON A TYPICAL RESIDENTIAL CUSTOMER BILL?

A. As shown on Exhibit SLF-3, the forecasted EDIS for residential customers in 2024 is an energy charge of $0.00047 per kWh. For an average residential customer that uses 1,000 kWh per month, this translates into $0.47 per month.

Q. HOW OFTEN WILL EDIS RATES BE UPDATED?

A. The update to EDIS rates will follow the same frequency as the current EDIS. EDIS rates will be filed for Commission approval by December 1 of each year for rates effective the forthcoming calendar year beginning January 1. EDIS rates will be based on forecasted costs for the forthcoming calendar year, as well as a reconciliation of prior costs and revenues. The reconciliation will be based upon the deferral balance recorded on the Company's books as of October 31, and a forecast of any anticipated incremental change to the deferral balance for the period of November 1 through December 31. The deferral balance is based upon the reconciliation of costs and revenues recorded monthly and may be represented as an over-collection or an under-collection. As such, the Company requests authorization to continue deferral accounting as part of the EDIS.

Q. WOULD THE EDIS ALWAYS REMAIN AS A SURCHARGE?

A. No. As previously discussed, the Company is proposing in this rate proceeding to roll into distribution rates the capital associated with investments placed into service through December 31, 2022, with a corresponding reduction in the surcharge upon conclusion of this rate proceeding. Similarly, capital associated with investments placed in service from January 2023 through December of the test year of a future base rate case will be proposed to be rolled into distribution rates and removed from surcharge recovery upon conclusion of that future rate proceeding. In other words, the EDIS will continually reset based upon the costs the Commission approves to be rolled into base distribution rates.

IV. CONCLUSION

Q. DOES THIS COMPLETE YOUR TESTIMONY AT THE TIME?

A. Yes, it does.

RESIDENTIAL SERVICE
SCHEDULE "R"

AVAILABILITY

Available for single-phase Residential Service through one meter. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$8.00 per month.

VARIABLE DISTRIBUTION CHARGE

Energy Charge
All kilowatt-hours.. $0.02556 per kilowatt-hour

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours.. $0.00396 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

ELECTRIC SUPPLY CHARGE

	Summer 06-01-2022 thru 09-30-2022	Non-Summer 10-01-2022 thru 05-31-2023
Energy Charge All kilowatt-hours	$0.05973 per kilowatt-hour	$0.06318 per kilowatt-hour

The Transmission and Electric Supply Charges apply only to Customers receiving Residential SOS from the Company. These charges do not apply to Customers obtaining Competitive Power Supply.

GENERAL SERVICE
SCHEDULE "G"

AVAILABILITY

Available for single-phase and three-phase Service at standard Company voltage throughout the entire territory served by the Company. The standard voltage depends upon the location, character and size of the Customer's load. This information can be furnished at any of the Company's offices. Service shall not be available for Standby or Maintenance Service such as that required for Alternative Generation Facilities. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$8.00 per month.

VARIABLE DISTRIBUTION CHARGES

Capacity Charge
Minimum kilowatts ....$1.80 per kilowatt
All kilowatts in excess of 7.5 measured as set forth under
“Determination of Capacity” ....$2.25 per kilowatt

Energy Charge
All kilowatt-hours... $0.02371 per kilowatt-hour

Voltage Discount

Company will furnish Service at one voltage and at one point from the Company's existing distribution system voltage. A voltage discount of 25¢ per kilowatt will apply when the Customer takes Service at a voltage between 2,000 and 15,000 volts and provides all facilities beyond the Point of Service. A voltage discount of 50¢ per kilowatt will apply when the Customer takes Service at a voltage greater than 15,000 volts and provides all facilities beyond the Point of Service.

Reactive Kilovolt-Ampere Charge

Reactive kilovolt-ampere charge is applied to the Customer’s reactive kilovolt-ampere capacity requirement in excess of 25% of the Customer’s kilowatt capacity.

Billing reactive kilovolt-amperes ....$0.40 per reactive kilovolt-ampere

GENERAL AND COMMERCIAL SERVICE
SCHEDULE "C”

AVAILABILITY

Available only at locations served as of November 26, 1991 for single-phase and three-phase Service at standard Company voltage below 15,000 volts. The standard voltage available depends upon the location, character and size of Customer's load. This information can be furnished at any of the Company's offices. Service shall not be available for Standby or Maintenance Service such as that required for Alternative Generation Facilities. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$8.00 per month.

VARIABLE DISTRIBUTION CHARGES

Minimum kilowatts ....$1.80 per kilowatt
Energy Charge
First block (0-350 kilowatt-hours).. $0.02371 per kilowatt-hour
Second block (next 350 kilowatt-hours).. $0.04489 per kilowatt-hour
Third block (over 700 kilowatt-hours).. $0.02371 per kilowatt-hour

Voltage Discount

Company will furnish Service at one voltage and at one point from the Company's existing distribution system voltage. Where Customer takes Service at a voltage between 2,000 and 15,000 volts and provides all facilities beyond the Service point, a voltage discount of 25¢ per kilowatt will apply.

Reactive Kilovolt-Ampere Charge

Reactive kilovolt-ampere charge is applied to the Customer’s reactive kilovolt-ampere capacity requirement in excess of 25% of the Customer’s kilowatt capacity.

Billing reactive kilovolt-amperes... $0.40 per reactive kilovolt-ampere

GENERAL SERVICE - ALL ELECTRIC
SCHEDULE "C-A"

AVAILABILITY

Available only at locations served or for which contracts have been signed as of April 9, 1973. All applicable surcharges, credits and taxes shall apply.

APPLICATION

This schedule applies to Customers contracting for electric Service to heat their entire establishment by the use of electricity and when all other electrical uses in the establishment are billed under this schedule. Not applicable to establishments whose primary operations are conducted outside the heated area.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$8.00 per month.

VARIABLE DISTRIBUTION CHARGES

Minimum kilowatts ....$1.44 per kilowatt
Energy Charge
All kilowatt-hours.. $0.02317 per kilowatt-hour

Voltage Discount

Company will furnish Service at one voltage and at one point from the Company's existing distribution system voltage. Where Customer takes Service at a voltage between 2,000 and 15,000 volts and provides all facilities beyond the Point of Service, a voltage discount of 25¢ per kilowatt will apply.

TRANSMISSION CHARGES

Minimum Charge ....$1.30 per month
Minimum kilowatts ....$0.14 per kilowatt
Energy Charge
First block (0-350 kilowatt-hours)... $0.00725 per kilowatt-hour
Second block (next 350 kilowatt-hours).. $0.00632 per kilowatt-hour
Third block (over 700 kilowatt-hours).. $0.00337 per kilowatt-hour

The Transmission Charges are based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

GENERAL SERVICE - ALL ELECTRIC
SCHEDULE "C-A" (Continued)

SERVICE SUPPLIED TO SCHOOLS AND CHURCHES WITH SPACE HEATING

When a school or church uses electric Service as the only means of space heating in a building, buildings, or in a separate area of a building then the kilowatt-hours used in the building, buildings, or separate area of a building will be billed at the above prices. When all energy uses, except as provided hereafter, for space heating, lighting, cooking, water heating, cooling (if any) and power are provided by electrical energy, all kilowatt-hours will be billed at the prices below. Any form of energy may be used for instruction, training and demonstration purposes and will be excluded from the above requirement.

A building, buildings, or separate area of a building not meeting the conditions of this provision shall be separately metered and billed under the applicable rate. The word school as used herein refers to a school operated through the use of public funds or by a non-profit organization.

A school building refers to a building containing any of the following facilities: classrooms, laboratories, manual arts shops, domestic science kitchens, gymnasium, dining areas, dormitories and other facilities used for educational purpose. Service for athletic field flood lighting shall be excluded from Service supplied under this provision and shall be billed for Service separately.

A church building refers to a building used principally for religious worship and Services.

MONTHLY RATE

DISTRIBUTION CHARGE

FIXED DISTRIBUTION CHARGE

$8.00 per month.

VARIABLE DISTRIBUTION CHARGE

Energy Charge
All kilowatt-hours... $0.01789 per kilowatt-hour

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours... $0.00381 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

POWER SERVICE
SCHEDULE "PH"

AVAILABILITY

Available for loads of 50 kilowatts or greater at standard single-phase and three-phase voltages. To maintain eligibility, Customer load must equal or exceed 50 kilowatts at least once during a rolling 12-month period. The standard voltages available depend upon location, character and size of Customer's load. This information can be furnished at any of the Company's offices. Service shall not be available for Standby or Maintenance Service such as that required for Alternative Generation Facilities. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$17.00

Capacity Charge
Minimum kilowatts ....$1.54 per kilowatt
All kilowatts...$2.41 per kilowatt

Energy Charge
All kilowatt-hours.. $0.00523 per kilowatt-hour

Voltage Discount

Company will furnish Service at one voltage and at one point from the Company's existing distribution system voltage. A voltage discount of 25¢ per kilowatt will apply when the Customer takes Service at a voltage between 2,000 and 15,000 volts and provides all facilities beyond the Point of Service. A voltage discount of 50¢ per kilowatt will apply when the Customer takes Service at a voltage greater than 15,000 volts and provides all facilities beyond the Point of Service.

Reactive Kilovolt-Ampere Charge

Reactive kilovolt-ampere charge is applied to the Customer's reactive kilovolt-ampere capacity requirement in excess of 25% of the Customer's kilowatt capacity.

Billing reactive kilovolt-amperes .... $0.40 per reactive kilovolt-ampere

THE POTOMAC EDISON COMPANY

Electric P.S.C. Md. No. 54
Second Revision of
Original Page No. 10
Canceling
First Revision of
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LARGE POWER SERVICE
SCHEDULE "PP"

AVAILABILITY

Available to Customers with a kilowatt capacity of 5,000 kilowatts or more that can be served from a 138,000/34,500 volt Load Center Substation located within 5 miles of the point of delivery to the Customer. To maintain eligibility, Customer load must equal or exceed 5,000 kilowatts at least once during a rolling 12-month period. Also available to Customers with a kilowatt capacity of 10,000 kilowatts and over, located adjacent to 138,000 volt transmission lines. Also available at 12,470 volts where the Company elects, at its sole option, to supply Service directly from an adjacent 138,000 volt transmission line by a single transformation. Service shall not be available for Standby or Maintenance Service such as that required for Alternative Generation Facilities. Service will be delivered and metered at 34,500 volts or over. An Electric Service Agreement must be executed. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$453.00

Capacity Charge
All kilowatts as set forth below under “Billing Capacity” ....$0.402 per kilowatt

Energy Charge
All kilowatt-hours.. $0.00083 per kilowatt-hour

Reactive Kilovolt-Ampere Charge

Reactive kilovolt-ampere charge is applied to the Customer’s reactive kilovolt-ampere capacity requirement in excess of 25% of the Customer’s Billing Capacity.

Billing reactive kilovolt-amperes .... $0.40 per reactive kilovolt-ampere

TRANSMISSION CHARGES

Capacity Charge
All kilowatts as set forth below under “Billing Capacity” ....$0.574 per kilowatt

Energy Charge
All kilowatt-hours.. $0.00118 per kilowatt-hour

The Transmission Charges are based on PJM’s Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

OUTDOOR LIGHTING
EQUIPMENT, MAINTENANCE, AND UNMETERED SERVICE
SCHEDULE EMU

AVAILABILITY

Available for roadway and other outdoor lighting supplied from overhead or underground secondary distribution system of the Company and contracted for by a Customer for lighting accessible areas. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

OVERHEAD SERVICE

High Pressure Sodium - Vertical Open Lens Luminaire ("OL")

		Installation Requires a Pole[1]	Installation on Existing Pole
9,500 Lumen-100 Watt	51 kWh	$20.56 per lamp	$10.40 per lamp

Mercury Vapor - Horizontal Luminaire (Cobra Head)

8,150 Lumen - 175 watt	74 kWh	$ 9.42 per lamp

High Pressure Sodium - Horizontal Luminaire (Cobra Head)

9,500 Lumen - 100 watt	51 kWh	$10.78 per lamp
22,000 Lumen - 200 watt	86 kWh	$16.44 per lamp
50,000 Lumen - 400 watt	167 kWh	$23.11 per lamp

Metal Halide - Horizontal Luminaire (Cobra Head)

36,000 Lumen - 400 watt	157 kWh	$25.13 per lamp
90,000 Lumen - 1000 watt	379 kWh	$25.48 per lamp

OUTDOOR LIGHTING
EQUIPMENT, MAINTENANCE, AND UNMETERED SERVICE
SCHEDULE EMU (Continued)

OVERHEAD SERVICE (Continued)

High Pressure Sodium Floodlight

22,000 Lumen - 200 watt ....86 kWh ....$18.49 per lamp
50,000 Lumen - 400 watt ....167 kWh ....$27.86 per lamp

Metal Halide Floodlight

36,000 Lumen - 400 watt ....157 kWh ....$29.25 per lamp
90,000 Lumen - 1000 watt ....379 kWh ....$28.27 per lamp

[1] Mounted on a 30' direct burial pole

UNDERGROUND SERVICE

High Pressure Sodium - Colonial Post Top Luminaire 14' Mounting Height

9,500 Lumen - 100 watt ....51 kWh ....$19.22 per lamp

Metal Halide - Colonial Post Top Luminaire 14' Mounting Height

11,600 Lumen - 175 watt ....74 kWh ....$26.86 per lamp

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OUTDOOR LIGHTING
EQUIPMENT, MAINTENANCE, AND UNMETERED SERVICE
SCHEDULE EMU (Continued)

UNDERGROUND SERVICE (Continued)

High Pressure Sodium - Horizontal Luminaire (Cobra Head) 30' Mounting Height

	Single Luminaire Per Pole	Each Additional Luminaire Per Pole
9,500 Lumen - 100 watt - 51 kWh	$28.74 per lamp	$10.78 per lamp
22,000 Lumen - 200 watt - 86 kWh	$32.04 per lamp	$16.44 per lamp
50,000 Lumen - 400 watt - 167 kWh	$38.72 per lamp	$23.11 per lamp

Metal Halide - Horizontal Luminaire (Cobra Head) 30' Mounting Height

	Single Luminaire Per Pole	Each Additional Luminaire Per Pole
36,000 Lumen - 400 watt - 157 kWh	$40.49 per lamp	$25.13 per lamp
90,000 lumen - 1,000 watt -379 kWh	$50.19 per lamp	$25.48 per lamp

High Pressure Sodium - Rectangular Luminaire (Shoe Box) 30' Mounting Height

		Single Luminaire Per Pole		Each Additional
		With base[1]	No base	Luminaire Per Pole
9,500 Lumen - 100 watt	51 kWh	$46.47 per lamp	$44.36	$24.46 per lamp
22,000 Lumen - 200 watt	86 kWh	$47.12 per lamp	$45.30	$25.46 per lamp
50,000 Lumen - 400 watt	167 kWh	$47.28 per lamp	$43.41	$23.56 per lamp

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OUTDOOR LIGHTING
EQUIPMENT, MAINTENANCE, AND UNMETERED SERVICE
SCHEDULE EMU (Continued)

Metal Halide - Rectangular Luminaire (Shoe Box) 30' Mounting Height

		With base[1]	No base	Each Additional Luminaire Per Pole
36,000 Lumen - 400 watt	157 kWh	$49.21 per lamp	$44.60	$25.43 per lamp

Metal Halide - Rectangular Area Luminaire (Shoe Box) 40' Mounting Height

90,000 Lumen - 1000 watt	379 kWh		$55.55	$33.06 per lamp

[1] With base includes the installation of a non-concrete power installed foundation where soil conditions warrant its application.

Note: The rating of lamps in lumens is for identification purposes only and shall approximate the manufacturer's standard rating. All luminaires are lighted from dusk to dawn aggregating approximately 4,200 hours per year.

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours.. $0.00079 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

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OUTDOOR LIGHTING
MAINTENANCE AND UNMETERED SERVICE
SCHEDULE MU

AVAILABILITY

Available for high-pressure sodium, mercury vapor, metal halide and incandescent lighting. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

High Pressure Sodium Vapor			Installed On Customer-Owned Pole	Installed On Company's Distribution System
9,500 Lumen	100 Watt	51 kWh	$ 3.20 per lamp	$ 4.82 per lamp
22,000 Lumen	200 Watt	86 kWh	$ 3.25 per lamp	$ 4.86 per lamp
50,000 Lumen	400 Watt	167 kWh	$ 7.99 per lamp	$ 9.56 per lamp
Mercury Vapor				
8,150 Lumen	175 Watt	74 kWh	$ 3.05 per lamp	$ 4.68 per lamp
11,500 Lumen	250 Watt	103 kWh	$ 5.96 per lamp	$ 7.58 per lamp
21,500 Lumen	400 Watt	162 kWh	$ 6.46 per lamp	$ 8.04 per lamp
60,000 Lumen	1000 Watt	386 kWh	$ 8.99 per lamp	$10.57 per lamp
Metal Halide				
11,600 Lumen	175 Watt	74 kWh	$ 4.96 per lamp	$ 6.54 per lamp
15,000 Lumen	250 Watt	103 kWh	$ 5.25 per lamp	$ 6.85 per lamp
36,000 Lumen	400 Watt	157 kWh	$ 8.62 per lamp	$10.25 per lamp
90,000 Lumen	1000 Watt	379 kWh	$10.54 per lamp	$12.13 per lamp

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OUTDOOR LIGHTING
MAINTENANCE AND UNMETERED SERVICE
SCHEDULE MU (Continued)

Incandescent

1,000 Lumen ...... 100 Watt.........37 kWh ....$ 5.07 per lamp.......................$ 6.65 per lamp
2,500 Lumen ...... 200 Watt.........71 kWh ....$ 5.15 per lamp.......................$ 6.73 per lamp
4,000 Lumen ...... 325 Watt.......115 kWh ....$ 5.41 per lamp.......................$ 6.99 per lamp
6,000 Lumen ...... 450 Watt.......158 kWh ....$ 5.61 per lamp.......................$ 7.20 per lamp

Note: The rating of the lamps in lumens is for identification and shall approximate the manufacturer's standard rating.

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours... $0.00079 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

ELECTRIC SUPPLY CHARGE

	Summer 06-01-2022 thru 09-30-2022	Non-Summer 10-01-2022 thru 05-31-2023
Energy Charge		
All kilowatt-hours..	$0.05417 per kilowatt-hour.........	$0.05512 per kilowatt-hour

The Transmission and Electric Supply Charges apply only to Customers receiving Type I SOS from the Company. These charges do not apply to Customers obtaining Competitive Power Supply.

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OUTDOOR LIGHTING
EQUIPMENT AND MAINTENANCE SERVICE
SCHEDULE EM

AVAILABILITY

Available for roadway and other outdoor lighting where energy is supplied by Customer's metered Service and contracted for by a Customer for lighting accessible areas. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

OVERHEAD SERVICE

	Installation on Existing Pole
Mercury Vapor-Horizontal Luminaire (Cobra Head)	
8,150 Lumen ....175 watt	$10.34 per lamp
High Pressure Sodium-Horizontal Luminaire (Cobra Head)	
9,500 Lumen ....100 watt	$10.72 per lamp
22,000 Lumen ....200 watt	$16.38 per lamp
50,000 Lumen ....400 watt	$18.76 per lamp
Metal Halide - Horizontal Luminaire (Cobra Head)	
36,000 Lumen ....400 watt	$19.68 per lamp
90,000 Lumen .....1000 watt	$25.01 per lamp
High Pressure Sodium Floodlight	
22,000 Lumen ....200 watt	$18.44 per lamp
50,000 Lumen ....400 watt	$21.76 per lamp
Metal Halide Floodlight	
36,000 Lumen ....400 watt	$23.21 per lamp
90,000 Lumen .....1000 watt	$27.09 per lamp

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OUTDOOR LIGHTING
EQUIPMENT AND MAINTENANCE SERVICE
SCHEDULE EM (Continued)

UNDERGROUND SERVICE

	Installation on Existing Pole
Metal Halide - Colonial Post Top Luminaire 14' Mounting Height	
11,600 Lumen ....175 watt	$26.80 per lamp

High Pressure Sodium - Horizontal Luminaire (Cobra Head) 30' Mounting Height

	Single Luminaire Per Pole	Each Additional Luminaire Per Pole
9,500 Lumen ....100 watt	$29.05 per lamp	$10.72 per lamp
22,000 Lumen ....200 watt	$33.27 per lamp	$16.38 per lamp
50,000 Lumen ....400 watt	$37.12 per lamp	$18.76 per lamp

Metal Halide - Horizontal Luminaire (Cobra Head) 30' Mounting Height

	Single Luminaire Per Pole	Each Additional Luminaire Per Pole
36,000 Lumen ....400 watt	$40.26 per lamp	$19.68 per lamp
90,000 Lumen ....1,000 watt	$49.72 per lamp	$25.01 per lamp

High Pressure Sodium - Rectangular Luminaire (Shoe Box) 30' Mounting Height

	Single Luminaire Per Pole		Each Additional Luminaire Per Pole
	With base[1]	No base	
9,500 Lumen ....100 watt	$47.09 per lamp	$43.49	$25.07 per lamp
22,000 Lumen ....200 watt	$47.68 per lamp	$44.39	$25.99 per lamp
50,000 Lumen ....400 watt	$47.75 per lamp	$44.64	$26.22 per lamp

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OUTDOOR LIGHTING
EQUIPMENT AND MAINTENANCE SERVICE
SCHEDULE EM (Continued)

UNDERGROUND SERVICE (Continued)

Metal Halide - Rectangular Luminaire (Shoe Box) 30' Mounting Height

		With base[1]	No base	Each Additional Luminaire Per Pole
36,000 Lumen	400 watt	$48.94 per lamp	$45.84	$27.42 per lamp

Metal Halide - Rectangular Area Luminaire (Shoe Box) 40' Mounting Height

90,000 Lumen	1000 watt	$55.92 per lamp		$32.59 per lamp

Note: The rating of lamps in lumens is for identification purposes only and shall approximate the manufacturer's standard rating.

[1]With base includes the installation of a non-concrete power installed foundation where soil conditions warrant its application.

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours.. $0.00000 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

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LED STREET LIGHTING SERVICE
SCHEDULE "LED"

COMPANY-OWNED AND MAINTAINED EQUIPMENT (COMPANY SUPPLIES UNMETERED ENERGY)

AVAILABILITY

Available for the illumination of streets, highways and other outdoor areas by Company owned and maintained Light Emitting Diode (LED) street lights where energy supplied from the Company's overhead or underground secondary distribution system is unmetered and lighting Service is contracted for by the Customer. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGE

	Installation on Existing Pole
LED Cobra Head Luminaire	
4,000 Lumen - 50 watt.................... 18 kWh	$ 8.03 per lamp
7,000 Lumen - 90 watt.................... 32 kWh	$10.10 per lamp
11,500 Lumen - 130 watt.................... 46 kWh	$10.74 per lamp
24,000 Lumen - 260 watt.................... 91 kWh	$16.72 per lamp
LED Acorn Post Top Luminaire	
2,500 Lumen - 50 watt.................... 18 kWh	$21.57 per lamp
5,000 Lumen - 90 watt.................... 32 kWh	$22.79 per lamp
LED Colonial Post Top Luminaire	
2,500 Lumen - 50 watt.................... 18 kWh	$12.91 per lamp
5,000 Lumen - 90 watt.................... 32 kWh	$14.22 per lamp

Note: The rating of lamps in lumens is for identification purposes only and shall approximate the manufacturer's standard rating. All luminaires are lighted from dusk to dawn aggregating approximately 4,200 hours per year.

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LED STREET LIGHTING SERVICE
SCHEDULE "LED" (Continued)

Underground Service will be installed where Service is supplied from an existing underground distribution system. Customer shall provide, at their expense, any excavating, backfilling, reconstructing, resurfacing and conduit necessary for the installation of the Company's underground cable. Customer shall provide and install conduit of size specified by the Company.

All Service and necessary maintenance will be performed only during regular working hours of the Company. If Service and necessary maintenance cannot be performed during regular working hours of the Company, for reasons beyond the Company's control, the incremental costs of performing such work shall be borne by the Customer.

REPLACEMENT OR REMOVAL

Costs associated with the replacement, relocation, alteration, or removal of existing street lighting equipment are not included as part of normal maintenance and will be the responsibility of the Customer. Examples of such activities include, but are not limited to, the replacement of an existing fixture, removal or relocation of a luminaire, bracket, and/or pole, or installation of a luminaire shield.

In the event of early termination for any reason prior to expiration of the initial term of the agreement, Customer shall pay either the balance of the agreement responsibility, less applicable energy charge, or the cost of installation and removal of equipment, whichever is less. Any remaining balance due for extra facilities, rearranging of facilities or other additional installed costs which were separately billed over the term of the agreement shall also become immediately due and payable.

GENERAL

All costs described in this schedule are actual costs or, where applicable, estimates based on standard engineering practice.

All Customer charges are subject to any applicable local, state and federal taxes.

Company shall not be liable for damages to the Customer for any failure in any lighting system which results from any cause beyond the Company's control.

Customers may negotiate a contract for Service on an individual basis, upon mutual agreement with the Company. Such contracts shall incorporate all terms and conditions of this tariff and may include additional terms and conditions regarding advanced functionality of the LED lights and associated equipment including, but not limited to, controllers, dimming capabilities, sensors, or other network enabled functions. All costs of the advanced functionalities shall be borne by the Customer. Rates, terms and conditions may be subject to final approval of the Commission.

All energy savings associated with Customer participation under this schedule shall count toward the Company's energy efficiency and peak demand reduction requirements arising as a result of Section 7-211, Annotated Code of Maryland.

LED STREET LIGHTING SERVICE
SCHEDULE "LED" (Continued)

Company Responsibilities

Company will, at its own cost, install, operate and maintain its standard outdoor lighting equipment with unmetered Service.

Company shall furnish luminaires at additional locations in accordance with Company practices upon the written order of Customer; Company shall increase size of any luminaire in the same Rate Schedule upon written order of Customer.

Customer Responsibilities

Customer shall provide to Company free of cost and with free access, a satisfactory right-of-way and location for Company's facilities necessary to supply Service on premises controlled by Customer. Facilities provided at Company's expense shall remain Company property.

Customer shall be responsible for selecting the lamp size and location of the luminaire which shall be in conformance with applicable safety standards and governmental regulations. Customer shall obtain appropriate approval for luminaires to be located on public thoroughfares.

Customer shall be responsible for reporting non-operating lighting systems to the Company.

CONTRACT

Company standard form of Outdoor Lighting Agreement shall be executed, when appropriate, along with applicable map showing location and size of all luminaires.

<u>CUSTOMER-OWNED AND MAINTAINED EQUIPMENT (COMPANY SUPPLIES UNMETERED ENERGY)</u>

AVAILABILITY

Available for the illumination of streets, highways and other outdoor areas by Customer owned and maintained LED street lights where energy supplied from the Company's overhead or underground secondary distribution system is unmetered and lighting Service is contracted for by the Customer. All applicable surcharges, credits and taxes shall apply.

This schedule is also applicable within private property such as private walkways, streets, roads, and when supply from the Company's distribution system is directly available and when lighting Service is contracted for by the owner thereof.

Available only for LED street lights that are served from a low voltage (120 volt) electric circuit.

LED STREET LIGHTING SERVICE
SCHEDULE "LED" (Continued)

This rate is not available to serve Customer-owned lighting systems in an area where there will be a mix of Company-owned and Customer-owned systems.

MONTHLY RATE

DISTRIBUTION CHARGE

Energy Charge
All kilowatt-hours.. $0.03581 per kilowatt-hour

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours.. $0.00079 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

ELECTRIC SUPPLY CHARGE

	Summer 06-01-2022 thru 09-30-2022	Non-Summer 10-01-2022 thru 05-31-2023
Energy Charge		
All kilowatt-hours...	$0.05417 per kilowatt-hour	$0.05512 per kilowatt-hour

The Transmission and Electric Supply Charges apply only to Customers receiving Type I SOS from the Company. These charges do not apply to Customers obtaining Competitive Power Supply.

Service rendered herein is unmetered with the monthly kWh billed for each light calculated based on the manufacturer's luminaire wattage rating and the average monthly burn hours (4,200 annual burn hours / 12 months per year).

LATE PAYMENT CHARGE

Applies to this schedule as set forth in Company Rule No. 12 of this tariff.

TERM OF CONTRACT

Service is sold under this schedule for a minimum period of thirty days.

OUTDOOR LIGHTING SERVICE
SCHEDULE "OL"

AVAILABILITY

Available for lighting Service sold prior to November 18, 1998 for outdoor lighting supplied from the existing overhead secondary distribution system of the Company and contracted for by a private Customer. The rating of lamps in lumens is for identification and shall approximate the manufacturer's standard rating. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

A. For each 9,500 lumen (100 watt) high-pressure sodium lamp (51 kWh)............................$10.40 per lamp. Company will provide lamp, photo-electric relay control equipment, fixture and upsweep arm not over 4 feet in length, and will mount same on an existing pole carrying secondary circuits.

B. Restricted to installations as of February 25, 1993

For each 8150 lumen (175 Watt) mercury vapor lamp (74 kWh)...$ 9.88 per lamp. Company will provide lamp, photo-electric relay control equipment, fixture and upsweep arm not over 4 feet in length, and will mount same on an existing pole carrying secondary circuits.

C. Restricted to installations as of February 25, 1993

For each 21,500 lumen (400 Watt) mercury vapor lamp (162 kWh)...................................$17.21 per lamp. Company will provide lamp, photo-electric relay control equipment, fixture and upsweep arm not over 6 feet in length, and will mount same on an existing pole carrying secondary circuits.

D. For each 22,000 lumen (200 watt) high pressure sodium lamp (86 kWh)...........................$18.81 per lamp Company will provide lamp, photo-electric relay control equipment, fixture and upsweep arm not over 6 feet in length, and will mount same on an existing pole carrying secondary circuits.

E. When facilities, in addition to those specified in paragraphs A., B., or C. are required to provide outdoor lighting Service, the Customer will pay in advance the cost of installing all additional facilities. For those facilities installed prior to September 9, 1985, where the Company provided facilities at a monthly rental, such monthly charges will continue at a rate of $4.25 for each standard distribution wood pole required, $0.026 per foot for each foot of span length of wires required and $4.25 for each KVA of transformer capacity installed.

F. The Customer may elect to own and maintain poles and secondary circuits on their property to accommodate the installation of the outdoor lighting fixture. Such poles and circuits shall meet Company specifications.

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PRIVATE OUTDOOR AREA LIGHTING SERVICE
SCHEDULE "AL"

AVAILABILITY

Available only for installations served prior to September 9, 1985, for lighting Service sold for pole-mounted outdoor area lighting supplied from the existing secondary distribution system of the Company and contracted for by a private Customer. The rating of lamps in lumens is for identification and shall approximate the manufacturer's standard rating. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

LIGHTING FIXTURE

Nominal Watts	Nominal Lumens	kWh	Area Lighting (Underground Service)	Floodlighting Overhead or Underground Service
MERCURY VAPOR				
175	8,150	74	$16.57	
400	21,500	162		$20.93
1,000	60,000	386		26.48
HIGH PRESSURE SODIUM				
400	50,000	167		27.86
QUARTZ IODINE				
500		176		21.97

POLES

Length	Wood Standard	Wood Other	Metal
14 foot		$ 8.76	$ 6.09
30 foot	$ 4.33		18.18
35 foot	6.06	9.22	
40 foot	6.49		

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PRIVATE OUTDOOR AREA LIGHTING SERVICE
SCHEDULE "AL" (Continued)

OVERHEAD CIRCUIT

$0.027 per foot for each foot of span length.

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours.. $0.00079 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

ELECTRIC SUPPLY CHARGE

	Summer 06-01-2022 thru 09-30-2022	Non-Summer 10-01-2022 thru 05-31-2023
Energy Charge		
All kilowatt-hours	$0.05417 per kilowatt-hour	$0.05512 per kilowatt-hour

The Transmission and Electric Supply Charges apply only to Customers receiving Type I SOS from the Company. These charges do not apply to Customers obtaining Competitive Power Supply.

LATE PAYMENT

Applies to this schedule as set forth in Company Rule No. 12 of this tariff.

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PRIVATE OUTDOOR AREA LIGHTING SERVICE
SCHEDULE "AL" (Continued)

GENERAL (Concluded)

When lighting is served from an underground circuit the Customer shall own, install and maintain all necessary concrete bases for poles to be installed in accordance with the Company specifications. The Customer shall also own, install and maintain all facilities including circuits, conduit and pedestals necessary to supply Service to the base of the pole.

CUSTOMER OWNED EQUIPMENT - COMPANY OPERATES AND MAINTAINS

Whenever the Customer furnishes, installs and owns the entire lighting system using equipment approved by and installed in a manner acceptable to the Company, the Company may, at its discretion, operate and maintain the system at the following rates.

DISTRIBUTION CHARGES

LAMP SIZE IN			TYPE OF FIXTURE	
NOMINAL WATTS	KWH	TYPE OF LAMP	BRACKET	POST TOP
250	103	Mercury Vapor	$ 5.96	
400	162	" "	6.46	
1,000	386	" "	8.99	
400	167	High Pressure Sodium	7.99	$7.99

The Company's responsibility under the aforementioned charges for maintaining the Customer owned lighting system is limited to photo control, relamping, cleaning fixtures and painting poles requiring paint. When the Customer's equipment is intermediate in size to those listed above the Customer shall pay the monthly charges applicable to the next larger size.

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STREET AND HIGHWAY LIGHTING SERVICE
SCHEDULE "MSL"

1. COMPANY OWNED AND MAINTAINED EQUIPMENT

AVAILABILITY

Available for lighting Service sold prior to November 18, 1998 for the lighting of public streets, public highways and other public outdoor areas in municipalities, governmental units and unincorporated communities where such Service can be supplied from the existing general distribution system. All applicable surcharges, credits and taxes shall apply.

This schedule is also applicable within private property which is open to the general public such as private walkways, streets, roads, when the property and buildings are under common ownership and when supply from the Company's distribution system is directly available and when lighting Service is contracted for by the owner thereof. The rating of lamps in lumens is for identification and shall approximate the manufacturer's standard rating.

MONTHLY RATE

DISTRIBUTION CHARGES

Lamp Size			Overhead Supply		Underground Supply Standard Pole		Multiple Units For Each
Nominal Watts	Nominal Lumens	kWh	Wood Pole	Metal Pole	Low Mounting	High Mounting	Additional Fixture Per Pole
High Pressure Sodium							
70	5,800	37	$10.21		$18.64	$28.18	$10.21
100	9,500	51	10.11		18.47	28.07	10.11
200	22,000	86	15.76			31.37	15.76
400	50,000	167	22.43	$38.04		38.04	22.43
High Pressure Sodium - Rectangular Enclosed Fixture							
100	9,500	51				43.70	23.80
200	22,000	86				44.63	24.78
400	50,000	167				42.73	22.87

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STREET AND HIGHWAY LIGHTING SERVICE
SCHEDULE "MSL" (Continued)

MONTHLY RATE (Continued)

DISTRIBUTION CHARGES (Continued)

Lamp Size: Nominal Watts	Lamp Size: Nominal Lumens	Kwh	Overhead Supply: Wood Pole	Overhead Supply: Metal Pole	Underground Supply Standard Pole: Low Mounting	Underground Supply Standard Pole: High Mounting	Multiple Units For Each Additional Fixture Per Pole
Mercury Vapor - Restricted to installations as of February 25, 1993:							
175	8,150	74	$ 8.74		$16.49		$ 8.18
Mercury Vapor - Restricted to installations as of June 14, 1982:							
100	4,000	45	9.99		14.40		
250	11,500	103	12.76			29.20	
Mercury Vapor - Restricted to installations as of October 17, 1988:							
400	21,500	162	12.87	28.94		28.94	12.08

All lamps are lighted from dusk to dawn every night, or for approximately 4,200 hours per annum. However, at the request of the Customer individual lamps may be operated continuously 24 hours per day. The monthly rate for each light continuously operated shall be the applicable rate above plus 60% of the base overhead supply wood pole monthly rate.

When the circuit length exceeds 150 feet per light there will be an additional monthly charge of $0.026 per foot for each foot of span length and $0.034 per foot for each underground trench foot. (This provision is restricted to locations as of September 9, 1985.)

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STREET AND HIGHWAY LIGHTING SERVICE
SCHEDULE "MSL" (Continued)

MONTHLY RATE

DISTRIBUTION CHARGES

The Company's supply of unmetered energy to the Customer's high pressure sodium street lighting system will be at the following rates:

Lamp Size			
Nominal Watts	Nominal Lumens	kWh	Monthly Rate
70	5,800	37	$ 3.62
100	9,500	51	3.48
200	22,000	86	4.25
400	50,000	167	7.18

When the Customer's equipment is intermediate in size to those listed above, the Customer shall pay the monthly rate applicable to the next larger size.

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours.. $0.00079 per kilowatt-hour

The Transmission Charge is based on PJM’s Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

THE POTOMAC EDISON COMPANY

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CO-GENERATION
SCHEDULE "CO-G"

AVAILABILITY

This schedule is applicable for purchases of electricity by the Company from such qualifying facilities (QF) as cogenerators or small power producers as defined in Part 292, Subpart B, of the Public Utility Regulatory Policies Act of 1978 regulations. The Company may require proof that the QF meets the requirements for a qualifying facility under those regulations.

This schedule is available for power to be supplied by the QF to the Company at a single point of delivery in amounts or not more than 5,000 kW for qualifying small power producers and 20,000 kW for qualifying cogenerators.
.

This schedule may be used in conjunction with any of the Company's filed Rate Schedules presently in effect and applicable to the supply of electric Service to a Customer.

MONTHLY PAYMENTS

Energy Payments:

If applicable, the Company may sell the QF’s energy in the PJM hourly real-time energy market provided the QF complies with all PJM requirements to qualify as a PJM generation resource. The Company will pay the QF the PJM real-time locational marginal price (LMP) at the APS Zone, or its successor, for each hour energy is produced and delivered to the Company, less any PJM ancillary charges, other related costs, and Company administrative costs.

Capacity Payments:

If applicable, the Company may offer the QF’s capacity in the PJM capacity market provided the QF complies with all PJM requirements to qualify as a PJM capacity resource. The Company will pay the QF the capacity revenues received from PJM, less Company administrative costs, any PJM penalties incurred by the Company as a result of the QF’s failure to perform, and other related costs.

CONNECTION CHARGE:

The QF will pay the installed cost of the metering equipment and a monthly charge for the recurring expense of the QF metering connection pursuant to Rule 10 of the Company’s Rules and Regulations Covering the Supply of Electric Service.

SIMULTANEOUS PURCHASE AND SALE OPTION

Each QF served under this schedule shall have the option of either a simultaneous purchase and sale or the sale of only its excess power. The selection of such option shall be expressed in an Electric Service Agreement and shall be for a period of not less than one year.

ISSUED BY SAMUEL L. BELCHER, PRESIDENT

Issued

Effective

CO-GENERATION
SCHEDULE "CO-G" (Continued)

TERM

One year or longer.

SALES TO QUALIFYING FACILITIES

Supplementary, backup, interruptible, maintenance, and station power will be supplied by the Company to the QF under the applicable standard Rate Schedules.

INTERCONNECTION COSTS

All interconnection costs including interconnection costs incurred by the Company which are necessary to purchase energy or energy and capacity from the QF or to supply power are the responsibility of the QF. The Company will provide a nonbinding estimate of all interconnection costs to be incurred by the Company.

The QF is responsible for providing, installing, owning, and maintaining at its expense all equipment on the QF's side of the interconnection point. The QF must submit its interconnection plans and specifications to the Company, and the Company shall accept or reject those plans. The Company will inspect and approve the installation prior to making the interconnection. The inspection will be conducted by the Company, and the results of the inspection will be provided to the QF. The costs of any additional Company inspection required shall be borne by the QF. The QF is also responsible for obtaining Company approval for equipment and material specifications prior to making any modifications.

(a) The review and/or acceptance by the Company of the application for interconnection or plans and specification for such interconnection submitted by a QF does not and shall not be construed (1) as confirming or endorsing the design of the QF's facilities or (2) as any warranty of safety, durability, or reliability of the facilities.

(b) The Company shall not, by reason of any review or acceptance of the plans and specifications or application for interconnection submitted by QF, be responsible for strength, details of design, adequacy, or capability of the QF's facilities; nor shall the Company's acceptance and/or review of said plans and specifications or application for interconnection be deemed an endorsement or warranty of those facilities.

The Company installs, owns, and maintains at the QF's expense all metering equipment needed to measure separately the electricity delivered to the Company. Access shall be granted by the QF to the Company's authorized representative during any reasonable hours to install, inspect, and maintain the Company's metering equipment.

ALTERNATIVE GENERATION SCHEDULE
SCHEDULE "AGS" (Continued)

Penalty

The maximum by which the Customer's kilowatt demands exceed the sum of the Customer's firm capacities (i.e., the sum of the Customer's Supplementary, Maintenance, and Standby Firm capacities as applicable) during each interruption period shall be subject to a penalty charge. Only one such penalty shall be assessed per interruption period. The first time that the Customer is notified by the Company to interrupt Service and the Customer fails to reduce load to not more than the sum of its firm capacities, a penalty of $10 per kilowatt shall be applied to those kilowatts in excess of firm capacities. Upon the second occurrence of such a failure to interrupt, a penalty of $10 per kilowatt calculated as set forth above shall be applied and interruptible Service shall not be available to the Customer for the next two years. Upon the third occurrence of such a failure to interrupt, a $10 per kilowatt penalty shall be applied and interruptible Service shall no longer be available to the Customer.

MONTHLY RATE

DISTRIBUTION CHARGE

FIXED DISTRIBUTION CHARGE

$17.00

Demand Charges

Firm Standby Power
All kilowatts..$1.216 per kilowatt

Interruptible Standby Power
All kilowatts..$1.151 per kilowatt

Firm or Interruptible Maintenance Power
All kilowatts..$1.134 per kilowatt

Reactive Kilovolt-Ampere Charge

Reactive kilovolt-ampere charge is applied to the Customer’s reactive kilovolt-ampere capacity requirement in excess of 25% of the Customer’s kilowatt capacity.

Billing reactive kilovolt-amperes .... $0.40 per reactive kilovolt-ampere

Energy Charge

All kilowatt-hours.. $0.00203 per kilowatt-hour

GENERATION STATION POWER
SCHEDULE "SP"

AVAILABILITY

Available to electric generation stations which are owned and/or operated by a qualified member of PJM who are unable to supply station power from other generation stations within PJM. Electric service must be supplied at one point of delivery and the Customer will be responsible for all transforming, controlling, regulating and protective equipment and its operation and maintenance.

MONTHLY BILLING

During any PJM billing period in which the Customer's net generation output is negative, the Customer shall pay the Company a charge based upon all Company Charges for Schedule "G" inclusive of Default Electricity Supply Service. During any PJM billing period in which the Customer's net generation output is positive:

1. Customers receiveing metered Service over 100 kilovolts shall pay the Company the Fixed Distribution Charge in accordance with Schedule "G".
2. Customers receiving metered Service under 100 kilovolts shall pay the Company the Fixed Distribution Charge in accordance with Schedule "G" along with the Distribution Charge portion of Schedule "G" kilowatt demand ratchets during the periods that such ratches are applicable.

Net generation output is positive when the Customer generates and delivers more power to the Company's electric system than it consumes from the electric system, as measured by the revenue meters.

Net generation output is negative when the Customer consumes more power from the Company's electric system than it generates and delivers to the electric system, as measured by the revenue meters.

ELECTRIC SERVICE AGREEMENT

Electric service hereunder shall be furnished in accordance with an Electric Service Agreement in accordance with the provisions of Schedule "G".

LATE PAYMENT CHARGE

Applies to this schedule as set forth in Company Rule No. 12 of this tariff.

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RESIDENTIAL SERVICE
SCHEDULE "R"

AVAILABILITY

Available for single-phase Residential Service through one meter. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$~~5~~8.~~70~~ 00 per month.

VARIABLE DISTRIBUTION CHARGE

Energy Charge
All kilowatt-hours.. $0.~~01750~~ 02556 per kilowatt-hour

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours.. $0.00396 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

ELECTRIC SUPPLY CHARGE

	Summer 06-01-2022 thru 09-30-2022	Non-Summer 10-01-2022 thru 05-31-2023
Energy Charge		
All kilowatt-hours	$0.05973 per kilowatt-hour	$0.06318 per kilowatt-hour

The Transmission and Electric Supply Charges apply only to Customers receiving Residential SOS from the Company. These charges do not apply to Customers obtaining Competitive Power Supply.

~~ISSUED BY SAMUEL L. BELCHER, PRESIDENT~~

~~Issued January 20, 2022~~ ~~Effective June 1, 2022~~

~~Approved at Public Service Commission Administrative Meeting of February 23, 2022~~
~~in Case Nos. 8908, 9056, and 9064~~

GENERAL SERVICE
SCHEDULE "G"

AVAILABILITY

Available for single-phase and three-phase Service at standard Company voltage throughout the entire territory served by the Company. The standard voltage depends upon the location, character and size of the Customer's load. This information can be furnished at any of the Company's offices. Service shall not be available for Standby or Maintenance Service such as that required for Alternative Generation Facilities. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$~~4~~8.00 per month.

VARIABLE DISTRIBUTION CHARGES

Capacity Charge

Minimum kilowatts ....$1.~~42~~ 80 per kilowatt

All kilowatts in excess of 7.5 measured as set forth under "Determination of Capacity" ....$~~1~~2.~~77~~ 25 per kilowatt

Energy Charge

All kilowatt-hours.. $0.~~01869~~ 02371 per kilowatt-hour

Voltage Discount

Company will furnish Service at one voltage and at one point from the Company's existing distribution system voltage. A voltage discount of 25¢ per kilowatt will apply when the Customer takes Service at a voltage between 2,000 and 15,000 volts and provides all facilities beyond the Point of Service. A voltage discount of 50¢ per kilowatt will apply when the Customer takes Service at a voltage greater than 15,000 volts and provides all facilities beyond the Point of Service.

Reactive Kilovolt-Ampere Charge

Reactive kilovolt-ampere charge is applied to the Customer's reactive kilovolt-ampere capacity requirement in excess of 25% of the Customer's kilowatt capacity.

Billing reactive kilovolt-amperes ....$0.40 per reactive kilovolt-ampere

THE POTOMAC EDISON COMPANY

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GENERAL AND COMMERCIAL SERVICE
SCHEDULE "C"

AVAILABILITY

Available only at locations served as of November 26, 1991 for single-phase and three-phase Service at standard Company voltage below 15,000 volts. The standard voltage available depends upon the location, character and size of Customer's load. This information can be furnished at any of the Company's offices. Service shall not be available for Standby or Maintenance Service such as that required for Alternative Generation Facilities. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$~~4~~8.00 per month.

VARIABLE DISTRIBUTION CHARGES

Minimum kilowatts ....$1.~~42~~ 80 per kilowatt
Energy Charge
First block (0-350 kilowatt-hours)... $0.~~01869~~ 02371 per kilowatt-hour
Second block (next 350 kilowatt-hours)................................. $0.~~03540~~ 04489 per kilowatt-hour
Third block (over 700 kilowatt-hours)..................................... $0.~~01869~~ 02371 per kilowatt-hour

Voltage Discount

Company will furnish Service at one voltage and at one point from the Company's existing distribution system voltage. Where Customer takes Service at a voltage between 2,000 and 15,000 volts and provides all facilities beyond the Service point, a voltage discount of 25¢ per kilowatt will apply.

Reactive Kilovolt-Ampere Charge

Reactive kilovolt-ampere charge is applied to the Customer's reactive kilovolt-ampere capacity requirement in excess of 25% of the Customer's kilowatt capacity.

Billing reactive kilovolt-amperes... $0.40 per reactive kilovolt-ampere

GENERAL SERVICE - ALL ELECTRIC
SCHEDULE "C-A"

AVAILABILITY

Available only at locations served or for which contracts have been signed as of April 9, 1973. All applicable surcharges, credits and taxes shall apply.

APPLICATION

This schedule applies to Customers contracting for electric Service to heat their entire establishment by the use of electricity and when all other electrical uses in the establishment are billed under this schedule. Not applicable to establishments whose primary operations are conducted outside the heated area.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$~~4~~8.00 per month.

VARIABLE DISTRIBUTION CHARGES

Minimum kilowatts .... $1.~~09~~ 44 per kilowatt
Energy Charge
All kilowatt-hours .... $0.~~01757~~ 02317 per kilowatt-hour

Voltage Discount

Company will furnish Service at one voltage and at one point from the Company's existing distribution system voltage. Where Customer takes Service at a voltage between 2,000 and 15,000 volts and provides all facilities beyond the Point of Service, a voltage discount of 25¢ per kilowatt will apply.

TRANSMISSION CHARGES

Minimum Charge .... $1.30 per month
Minimum kilowatts .... $0.14 per kilowatt
Energy Charge
First block (0-350 kilowatt-hours) .... $0.00725 per kilowatt-hour
Second block (next 350 kilowatt-hours) .... $0.00632 per kilowatt-hour
Third block (over 700 kilowatt-hours) .... $0.00337 per kilowatt-hour

The Transmission Charges are based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

GENERAL SERVICE - ALL ELECTRIC
SCHEDULE "C-A" (Continued)

SERVICE SUPPLIED TO SCHOOLS AND CHURCHES WITH SPACE HEATING

When a school or church uses electric Service as the only means of space heating in a building, buildings, or in a separate area of a building then the kilowatt-hours used in the building, buildings, or separate area of a building will be billed at the above prices. When all energy uses, except as provided hereafter, for space heating, lighting, cooking, water heating, cooling (if any) and power are provided by electrical energy, all kilowatt-hours will be billed at the prices below. Any form of energy may be used for instruction, training and demonstration purposes and will be excluded from the above requirement.

A building, buildings, or separate area of a building not meeting the conditions of this provision shall be separately metered and billed under the applicable rate. The word school as used herein refers to a school operated through the use of public funds or by a non-profit organization.

A school building refers to a building containing any of the following facilities: classrooms, laboratories, manual arts shops, domestic science kitchens, gymnasium, dining areas, dormitories and other facilities used for educational purpose. Service for athletic field flood lighting shall be excluded from Service supplied under this provision and shall be billed for Service separately.

A church building refers to a building used principally for religious worship and Services.

MONTHLY RATE

DISTRIBUTION CHARGE

FIXED DISTRIBUTION CHARGE

$~~4~~8.00 per month.

VARIABLE DISTRIBUTION CHARGE

Energy Charge
All kilowatt-hours.. $0.~~01357~~ 01789 per kilowatt-hour

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours... $0.00381 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

THE POTOMAC EDISON COMPANY

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POWER SERVICE
SCHEDULE "PH"

AVAILABILITY

Available for loads of 50 kilowatts or greater at standard single-phase and three-phase voltages. To maintain eligibility, Customer load must equal or exceed 50 kilowatts at least once during a rolling 12-month period. The standard voltages available depend upon location, character and size of Customer's load. This information can be furnished at any of the Company's offices. Service shall not be available for Standby or Maintenance Service such as that required for Alternative Generation Facilities. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$17.00

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Capacity Charge
Minimum kilowatts ....$1.~~14~~ 54 per kilowatt
All kilowatts..$~~1~~2.~~78~~ 41 per kilowatt

Energy Charge
All kilowatt-hours.. $0.~~00386~~ 00523 per kilowatt-hour

Voltage Discount

Company will furnish Service at one voltage and at one point from the Company's existing distribution system voltage. A voltage discount of 25¢ per kilowatt will apply when the Customer takes Service at a voltage between 2,000 and 15,000 volts and provides all facilities beyond the Point of Service. A voltage discount of 50¢ per kilowatt will apply when the Customer takes Service at a voltage greater than 15,000 volts and provides all facilities beyond the Point of Service.

Reactive Kilovolt-Ampere Charge

Reactive kilovolt-ampere charge is applied to the Customer’s reactive kilovolt-ampere capacity requirement in excess of 25% of the Customer’s kilowatt capacity.

Billing reactive kilovolt-amperes .... $0.40 per reactive kilovolt-ampere

~~ISSUED BY SAMUEL L. BELCHER, PRESIDENT~~

~~Issued October 28, 2021~~ ~~Effective November 1, 2021~~

~~Issued under Order No. 89971 dated October 26, 2021 in Case No. 9490.~~

THE POTOMAC EDISON COMPANY Electric P.S.C. Md. No. 54

LARGE POWER SERVICE
SCHEDULE "PP"

AVAILABILITY

Available to Customers with a kilowatt capacity of 5,000 kilowatts or more that can be served from a 138,000/34,500 volt Load Center Substation located within 5 miles of the point of delivery to the Customer. To maintain eligibility, Customer load must equal or exceed 5,000 kilowatts at least once during a rolling 12-month period. Also available to Customers with a kilowatt capacity of 10,000 kilowatts and over, located adjacent to 138,000 volt transmission lines. Also available at 12,470 volts where the Company elects, at its sole option, to supply Service directly from an adjacent 138,000 volt transmission line by a single transformation. Service shall not be available for Standby or Maintenance Service such as that required for Alternative Generation Facilities. Service will be delivered and metered at 34,500 volts or over. An Electric Service Agreement must be executed. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

FIXED DISTRIBUTION CHARGE

$453.00

Capacity Charge
All kilowatts as set forth below under "Billing Capacity"..........................$0.~~286~~ 402 per kilowatt

Energy Charge
All kilowatt-hours.. $0.~~00059~~ 00083 per kilowatt-hour

Reactive Kilovolt-Ampere Charge

Reactive kilovolt-ampere charge is applied to the Customer's reactive kilovolt-ampere capacity requirement in excess of 25% of the Customer's Billing Capacity.

Billing reactive kilovolt-amperes .... $0.40 per reactive kilovolt-ampere

TRANSMISSION CHARGES

Capacity Charge
All kilowatts as set forth below under "Billing Capacity".................................$0.574 per kilowatt

Energy Charge
All kilowatt-hours... $0.00118 per kilowatt-hour

The Transmission Charges are based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

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OUTDOOR LIGHTING
EQUIPMENT, MAINTENANCE, AND UNMETERED SERVICE
SCHEDULE EMU

AVAILABILITY

Available for roadway and other outdoor lighting supplied from overhead or underground secondary distribution system of the Company and contracted for by a Customer for lighting accessible areas. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

OVERHEAD SERVICE

High Pressure Sodium - Vertical Open Lens Luminaire ("OL")

	Installation Requires a Pole[1]	Installation on Existing Pole
9,500 Lumen-100 Watt ....51 kWh	$~~17~~20.~~41~~ 56 per lamp	$~~8~~10.~~81~~ 40 per lamp

Mercury Vapor - Horizontal Luminaire (Cobra Head)

8,150 Lumen - 175 watt ....74 kWh ....$~~7~~9.~~98~~ 42 per lamp

High Pressure Sodium - Horizontal Luminaire (Cobra Head)

9,500 Lumen - 100 watt ....51 kWh ....$~~9~~10.~~13~~ 78 per lamp
22,000 Lumen - 200 watt ....86 kWh ....$~~13~~16.~~92~~ 44 per lamp
50,000 Lumen - 400 watt ....167 kWh ....$~~19~~23.~~57~~ 11 per lamp

Metal Halide - Horizontal Luminaire (Cobra Head)

36,000 Lumen - 400 watt ....157 kWh ....$~~21~~25.~~28~~ 13 per lamp
90,000 Lumen - 1000 watt ....379 kWh ....$~~21~~25.~~58~~ 48 per lamp

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OUTDOOR LIGHTING
EQUIPMENT, MAINTENANCE, AND UNMETERED SERVICE
SCHEDULE EMU (Continued)

OVERHEAD SERVICE (Continued)

High Pressure Sodium Floodlight

22,000 Lumen - 200 watt ....86 kWh ....$~~15~~18.~~66~~ 49 per lamp
50,000 Lumen - 400 watt ....167 kWh ....$~~23~~27.~~60~~ 86 per lamp

Metal Halide Floodlight

36,000 Lumen - 400 watt ....157 kWh ....$~~24~~29.~~77~~ 25 per lamp
90,000 Lumen - 1000 watt ....379 kWh ....$~~23~~28.~~94~~ 27 per lamp

[1] Mounted on a 30' direct burial pole

UNDERGROUND SERVICE

High Pressure Sodium - Colonial Post Top Luminaire 14' Mounting Height

9,500 Lumen - 100 watt ....51 kWh ....$~~16~~19.~~28~~ 22 per lamp

Metal Halide - Colonial Post Top Luminaire 14' Mounting Height

11,600 Lumen - 175 watt ....74 kWh ....$~~22~~26.~~75~~ 86 per lamp

~~ISSUED BY SAMUEL L. BELCHER, PRESIDENT~~

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THE POTOMAC EDISON COMPANY

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OUTDOOR LIGHTING
EQUIPMENT, MAINTENANCE, AND UNMETERED SERVICE
SCHEDULE EMU (Continued)

UNDERGROUND SERVICE (Continued)

High Pressure Sodium - Horizontal Luminaire (Cobra Head) 30' Mounting Height

	Single Luminaire Per Pole	Each Additional Luminaire Per Pole
9,500 Lumen - 100 watt - 51 kWh	$~~24~~28.~~34~~ 74 per lamp	$~~9~~10.~~13~~ 78 per lamp
22,000 Lumen - 200 watt - 86 kWh	$~~27~~32.~~14~~ 04 per lamp	$~~13~~16.~~92~~ 44 per lamp
50,000 Lumen - 400 watt - 167 kWh	$~~32~~38.~~79~~ 72 per lamp	$~~19~~23.~~57~~ 11 per lamp

Metal Halide - Horizontal Luminaire (Cobra Head) 30' Mounting Height

	Single Luminaire Per Pole	Each Additional Luminaire Per Pole
36,000 Lumen - 400 watt - 157 kWh	$~~34~~40.~~29~~ 49 per lamp	$~~21~~25.~~28~~ 13 per lamp
90,000 lumen - 1,000 watt -379 kWh	$~~42~~50.~~51~~ 19 per lamp	$~~21~~25.~~58~~ 48 per lamp

High Pressure Sodium - Rectangular Luminaire (Shoe Box) 30' Mounting Height

	Single Luminaire Per Pole With base[1]	Single Luminaire Per Pole No base	Each Additional Luminaire Per Pole
9,500 Lumen - 100 watt 51 kWh	$~~39~~46.~~36~~ 47 per lamp	$~~37~~44.~~57~~36	$~~20~~24.~~72~~ 46 per lamp
22,000 Lumen - 200 watt 86 kWh	$~~39~~47.~~91~~ 12 per lamp	$~~38~~45.~~37~~30	$~~21~~25.~~56~~ 46 per lamp
50,000 Lumen - 400 watt 167 kWh	$~~40~~47.~~04~~ 28 per lamp	$~~36~~43.~~77~~41	$~~19~~23.~~95~~ 56 per lamp

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OUTDOOR LIGHTING
EQUIPMENT, MAINTENANCE, AND UNMETERED SERVICE
SCHEDULE EMU (Continued)

Metal Halide - Rectangular Luminaire (Shoe Box) 30' Mounting Height

	With base[1]	No base	Each Additional Luminaire Per Pole
36,000 Lumen - 400 watt...... 157 kWh	$~~41~~49.~~68~~21 per lamp	$~~37~~44.~~77~~60	$~~21~~25.~~54~~43 per lamp

Metal Halide - Rectangular Area Luminaire (Shoe Box) 40' Mounting Height

	With base[1]	No base	Each Additional Luminaire Per Pole
90,000 Lumen - 1000 watt...... 379 kWh		$~~47~~55.~~05~~55	$~~28~~33.~~00~~06 per lamp

[1] With base includes the installation of a non-concrete power installed foundation where soil conditions warrant its application.

Note: The rating of lamps in lumens is for identification purposes only and shall approximate the manufacturer's standard rating. All luminaires are lighted from dusk to dawn aggregating approximately 4,200 hours per year.

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours.. $0.00079 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

OUTDOOR LIGHTING
MAINTENANCE AND UNMETERED SERVICE
SCHEDULE MU

AVAILABILITY

Available for high-pressure sodium, mercury vapor, metal halide and incandescent lighting. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

	Installed On Customer-Owned Pole	Installed On Company's Distribution System
High Pressure Sodium Vapor		
9,500 Lumen ...... 100 Watt .... 51 kWh	$ ~~2~~3.~~71~~ 20 per lamp	$ 4.~~08~~ 82 per lamp
22,000 Lumen ...... 200 Watt .... 86 kWh	$ ~~2~~3.~~75~~ 25 per lamp	$ 4.~~12~~ 86 per lamp
50,000 Lumen ...... 400 Watt .... 167 kWh	$ ~~6~~7.~~77~~ 99 per lamp	$ ~~8~~9.~~10~~ 56 per lamp
Mercury Vapor		
8,150 Lumen ...... 175 Watt .... 74 kWh	$ ~~2~~3.~~58~~ 05 per lamp	$ ~~3~~4.~~96~~ 68 per lamp
11,500 Lumen ...... 250 Watt .... 103 kWh	$ 5.~~05~~ 96 per lamp	$ ~~6~~7.~~42~~ 58 per lamp
21,500 Lumen ...... 400 Watt .... 162 kWh	$ ~~5~~6.~~47~~ 46 per lamp	$ ~~6~~8.~~81~~ 04 per lamp
60,000 Lumen .... 1000 Watt .... 386 kWh	$ ~~7~~8.~~61~~ 99 per lamp	$~~8~~10.~~95~~ 57 per lamp
Metal Halide		
11,600 Lumen ...... 175 Watt .... 74 kWh	$ 4.~~20~~ 96 per lamp	$ ~~5~~6.54 per lamp
15,000 Lumen ...... 250 Watt .... 103 kWh	$ 4~~5~~5.~~45~~ 25 per lamp	$ ~~5~~6.~~80~~ 85 per lamp
36,000 Lumen ...... 400 Watt .... 157 kWh	$ ~~7~~8.~~30~~ 62 per lamp	$~~8~~10.~~68~~ 25 per lamp
90,000 Lumen .... 1000 Watt .... 379 kWh	$~~8~~10.~~93~~ 54 per lamp	$~~10~~12.~~27~~ 13 per lamp

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OUTDOOR LIGHTING
MAINTENANCE AND UNMETERED SERVICE
SCHEDULE MU (Continued)

Incandescent

1,000 Lumen ...... 100 Watt......... 37 kWh ... $ ~~4~~5.~~29~~ 07 per lamp.................$ ~~5~~6.~~63~~ 65 per lamp
2,500 Lumen ...... 200 Watt......... 71 kWh ... $ ~~4~~5.~~36~~ 15 per lamp.................$ ~~5~~6.~~70~~ 73 per lamp
4,000 Lumen ...... 325 Watt....... 115 kWh ... $ ~~4~~5.~~58~~ 41 per lamp.................$ ~~5~~6.~~92~~ 99 per lamp
6,000 Lumen ...... 450 Watt....... 158 kWh ... $ ~~4~~5.~~75~~ 61 per lamp.................$ ~~6~~7.~~10~~ 20 per lamp

Note: The rating of the lamps in lumens is for identification and shall approximate the manufacturer's standard rating.

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours... $0.00079 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

ELECTRIC SUPPLY CHARGE

	Summer 06-01-2022 thru 09-30-2022	Non-Summer 10-01-2022 thru 05-31-2023
Energy Charge		
All kilowatt-hours..	$0.05417 per kilowatt-hour	$0.05512 per kilowatt-hour

The Transmission and Electric Supply Charges apply only to Customers receiving Type I SOS from the Company. These charges do not apply to Customers obtaining Competitive Power Supply.

~~ISSUED BY SAMUEL L. BELCHER, PRESIDENT~~

~~Issued April 21, 2022~~ ~~Effective June 1, 2022~~

~~Approved at Public Service Commission Administrative Meeting of May 25, 2022~~
~~in Case Nos. 8908, 9056, and 9064~~

OUTDOOR LIGHTING
EQUIPMENT AND MAINTENANCE SERVICE
SCHEDULE EM

AVAILABILITY

Available for roadway and other outdoor lighting where energy is supplied by Customer's metered Service and contracted for by a Customer for lighting accessible areas. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

OVERHEAD SERVICE

	Installation on Existing Pole
Mercury Vapor-Horizontal Luminaire (Cobra Head)	
8,150 Lumen ....175 watt	$~~8~~10.~~76~~34 per lamp
High Pressure Sodium-Horizontal Luminaire (Cobra Head)	
9,500 Lumen ....100 watt	$~~9~~10.~~08~~72 per lamp
22,000 Lumen ....200 watt	$~~13~~16.~~87~~38 per lamp
50,000 Lumen ....400 watt	$~~15~~18.~~89~~76 per lamp
Metal Halide - Horizontal Luminaire (Cobra Head)	
36,000 Lumen ....400 watt	$~~16~~19.~~67~~68 per lamp
90,000 Lumen .....1000 watt	$~~21~~25.~~18~~01 per lamp
High Pressure Sodium Floodlight	
22,000 Lumen ....200 watt	$~~15~~18.~~62~~44 per lamp
50,000 Lumen ....400 watt	$~~18~~21.~~43~~76 per lamp
Metal Halide Floodlight	
36,000 Lumen ....400 watt	$~~19~~23.~~66~~21 per lamp
90,000 Lumen .....1000 watt	$~~22~~27.~~94~~09 per lamp

OUTDOOR LIGHTING
EQUIPMENT AND MAINTENANCE SERVICE
SCHEDULE EM (Continued)

UNDERGROUND SERVICE

Metal Halide - Colonial Post Top Luminaire 14' Mounting Height

	Installation on Existing Pole
11,600 Lumen ....175 watt	$~~22~~26.~~70~~ 80 per lamp

High Pressure Sodium - Horizontal Luminaire (Cobra Head) 30' Mounting Height

	Single Luminaire Per Pole	Each Additional Luminaire Per Pole
9,500 Lumen ....100 watt	$~~24~~29.~~60~~ 05 per lamp	$~~9~~10.~~08~~ 72 per lamp
22,000 Lumen ....200 watt	$~~28~~33.~~18~~ 27 per lamp	$~~13~~16.~~87~~ 38 per lamp
50,000 Lumen ....400 watt	$~~31~~37.~~44~~ 12 per lamp	$~~15~~18.~~89~~ 76 per lamp

Metal Halide - Horizontal Luminaire (Cobra Head) 30' Mounting Height

36,000 Lumen ....400 watt	$~~34~~40.~~10~~ 26 per lamp	$~~16~~19.~~67~~ 68 per lamp
90,000 Lumen ....1,000 watt	$~~42~~49.~~11~~ 72 per lamp	$~~21~~25.~~18~~ 01 per lamp

High Pressure Sodium - Rectangular Luminaire (Shoe Box) 30' Mounting Height

	Single Luminaire Per Pole: With base[1]	Single Luminaire Per Pole: No base	Each Additional Luminaire Per Pole
9,500 Lumen ....100 watt	$~~39~~47.~~88~~ 09 per lamp	$~~36~~43.~~83~~49	$~~21~~25.~~23~~ 07 per lamp
22,000 Lumen ....200 watt	$~~40~~47.~~38~~ 68 per lamp	$~~37~~44.~~60~~39	$~~22~~25.~~01~~ 99 per lamp
50,000 Lumen ....400 watt	$~~40~~47.~~44~~ 75 per lamp	$~~37~~44.~~81~~64	$~~22~~26.~~21~~ 22 per lamp

THE POTOMAC EDISON COMPANY

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OUTDOOR LIGHTING
EQUIPMENT AND MAINTENANCE SERVICE
SCHEDULE EM (Continued)

UNDERGROUND SERVICE (Continued)

Metal Halide - Rectangular Luminaire (Shoe Box) 30' Mounting Height

	With base[1]	No base	Each Additional Luminaire Per Pole
36,000 Lumen ....400 watt.............	$~~41~~48.~~45~~ 94 per lamp	$~~38~~45.~~82~~84	$~~23~~27.~~22~~ 42 per lamp

Metal Halide - Rectangular Area Luminaire (Shoe Box) 40' Mounting Height

90,000 Lumen .....1000 watt............. $~~47~~55.~~36~~ 92 per lamp............................$~~27~~32.~~60~~ 59 per lamp

Note: The rating of lamps in lumens is for identification purposes only and shall approximate the manufacturer's standard rating.

[1]With base includes the installation of a non-concrete power installed foundation where soil conditions warrant its application.

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours.. $0.00000 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

~~ISSUED BY SAMUEL L. BELCHER, PRESIDENT~~

~~Issued October 28, 2021~~ ~~Effective November 1, 2021~~

~~Issued under Order No. 89971 dated October 26, 2021 in Case No. 9490.~~

THE POTOMAC EDISON COMPANY

Electric P.S.C. Md. No. 54
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LED STREET LIGHTING SERVICE
SCHEDULE "LED"

COMPANY-OWNED AND MAINTAINED EQUIPMENT (COMPANY SUPPLIES UNMETERED ENERGY)

AVAILABILITY

Available for the illumination of streets, highways and other outdoor areas by Company owned and maintained Light Emitting Diode (LED) street lights where energy supplied from the Company's overhead or underground secondary distribution system is unmetered and lighting Service is contracted for by the Customer. All applicable surcharges, credits and taxes shall apply.

~~Available only for group installations of 12 or more LED streetlights per Customer.~~

MONTHLY RATE

DISTRIBUTION CHARGE

			Installation on Existing Pole
LED Cobra Head Luminaire			
4,000 Lumen -	50 watt	18 kWh	$ ~~6~~8.~~80~~ 03 per lamp
7,000 Lumen -	90 watt	32 kWh	$~~8~~10.~~55~~ 10 per lamp
11,500 Lumen -	130 watt	46 kWh	$~~9~~10.~~10~~ 74 per lamp
24,000 Lumen -	260 watt	91 kWh	$~~14~~16.~~16~~ 72 per lamp
LED Acorn Post Top Luminaire			
2,500 Lumen -	50 watt	18 kWh	$~~18~~21.~~27~~ 57 per lamp
5,000 Lumen -	90 watt	32 kWh	$~~19~~22.~~30~~ 79 per lamp
LED Colonial Post Top Luminaire			
2,500 Lumen -	50 watt	18 kWh	$~~10~~12.~~93~~ 91 per lamp
5,000 Lumen -	90 watt	32 kWh	$~~12~~14.~~04~~ 22 per lamp

Note: The rating of lamps in lumens is for identification purposes only and shall approximate the manufacturer's standard rating. All luminaires are lighted from dusk to dawn aggregating approximately 4,200 hours per year.

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LED STREET LIGHTING SERVICE
SCHEDULE "LED" (Continued)

Underground Service will be installed where Service is supplied from an existing underground distribution system. Customer shall provide, at their expense, any excavating, backfilling, reconstructing, resurfacing and conduit necessary for the installation of the Company's underground cable. Customer shall provide and install conduit of size specified by the Company.

All Service and necessary maintenance will be performed only during regular working hours of the Company. If Service and necessary maintenance cannot be performed during regular working hours of the Company, for reasons beyond the Company's control, the incremental costs of performing such work shall be borne by the Customer.

REPLACEMENT OR REMOVAL

Costs associated with the replacement, relocation, alteration, or removal of existing street lighting equipment are not included as part of normal maintenance and will be the responsibility of the Customer. Examples of such activities include, but are not limited to, the replacement of an existing fixture, removal or relocation of a luminaire, bracket, and/or pole, or installation of a luminaire shield.

In the event of early termination for any reason prior to expiration of the initial term of the agreement, Customer shall pay either the balance of the agreement responsibility, less applicable energy charge, or the cost of installation and removal of equipment, whichever is less. Any remaining balance due for extra facilities, rearranging of facilities or other additional installed costs which were separately billed over the term of the agreement shall also become immediately due and payable.

GENERAL

All costs described in this schedule are actual costs or, where applicable, estimates based on standard engineering practice.

All Customer charges are subject to any applicable local, state and federal taxes.

Company shall not be liable for damages to the Customer for any failure in any lighting system which results from any cause beyond the Company's control.

Customers may negotiate a contract for Service on an individual basis, upon mutual agreement with the Company. Such contracts shall incorporate all terms and conditions of this tariff and may include additional terms and conditions regarding advanced functionality of the LED lights and associated equipment including, but not limited to, controllers, dimming capabilities, sensors, or other network enabled functions. All costs of the advanced functionalities shall be borne by the Customer. Rates, terms and conditions may be subject to final approval of the Commission.

All energy savings associated with Customer participation under this schedule shall count toward the Company's energy efficiency and peak demand reduction requirements arising as a result of Section 7-211, Annotated Code of Maryland.

~~Company Responsibilities~~

~~Company will, at its own cost, install, operate and maintain its standard outdoor lighting equipment with unmetered Service.~~

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LED STREET LIGHTING SERVICE
SCHEDULE "LED" (Continued)

Company Responsibilities

Company will, at its own cost, install, operate and maintain its standard outdoor lighting equipment with unmetered Service.

Company shall furnish luminaires at additional locations in accordance with Company practices upon the written order of Customer; Company shall increase size of any luminaire in the same Rate Schedule upon written order of Customer.

Customer Responsibilities

Customer shall provide to Company free of cost and with free access, a satisfactory right-of-way and location for Company's facilities necessary to supply Service on premises controlled by Customer. Facilities provided at Company's expense shall remain Company property.

Customer shall be responsible for selecting the lamp size and location of the luminaire which shall be in conformance with applicable safety standards and governmental regulations. Customer shall obtain appropriate approval for luminaires to be located on public thoroughfares.

Customer shall be responsible for reporting non-operating lighting systems to the Company.

CONTRACT

Company standard form of Outdoor Lighting Agreement shall be executed, when appropriate, along with applicable map showing location and size of all luminaires.

CUSTOMER-OWNED AND MAINTAINED EQUIPMENT (COMPANY SUPPLIES UNMETERED ENERGY)

AVAILABILITY

Available for the illumination of streets, highways and other outdoor areas by Customer owned and maintained LED street lights where energy supplied from the Company's overhead or underground secondary distribution system is unmetered and lighting Service is contracted for by the Customer. All applicable surcharges, credits and taxes shall apply.

This schedule is also applicable within private property such as private walkways, streets, roads, and when supply from the Company's distribution system is directly available and when lighting Service is contracted for by the owner thereof.

Available only for LED street lights that are served from a low voltage (120 volt) electric circuit.

~~Issued under Order No. 89072 dated March 22, 2019 in Case No. 9490.~~

LED STREET LIGHTING SERVICE
SCHEDULE "LED" (Continued)

This rate is not available to serve Customer-owned lighting systems in an area where there will be a mix of Company-owned and Customer-owned systems.

MONTHLY RATE

DISTRIBUTION CHARGE

Energy Charge
All kilowatt-hours.. $0.~~03033~~ 03581 per kilowatt-hour

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours... $0.00079 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

ELECTRIC SUPPLY CHARGE

	Summer 06-01-2022 thru 09-30-2022	Non-Summer 10-01-2022 thru 05-31-2023
Energy Charge All kilowatt-hours..	$0.05417 per kilowatt-hour.........	$0.05512 per kilowatt-hour

The Transmission and Electric Supply Charges apply only to Customers receiving Type I SOS from the Company. These charges do not apply to Customers obtaining Competitive Power Supply.

Service rendered herein is unmetered with the monthly kWh billed for each light calculated based on the manufacturer's luminaire wattage rating and the average monthly burn hours (4,200 annual burn hours / 12 months per year).

LATE PAYMENT CHARGE

Applies to this schedule as set forth in Company Rule No. 12 of this tariff.

TERM OF CONTRACT

Service is sold under this schedule for a minimum period of thirty days.

~~ISSUED BY SAMUEL L. BELCHER, PRESIDENT~~

~~Issued April 21, 2022~~ ~~Effective June 1, 2022~~

~~Approved at Public Service Commission Administrative Meeting of May 25, 2022~~
~~in Case Nos. 8908, 9056, and 9064~~

THE POTOMAC EDISON COMPANY

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OUTDOOR LIGHTING SERVICE
SCHEDULE "OL"

AVAILABILITY

Available for lighting Service sold prior to November 18, 1998 for outdoor lighting supplied from the existing overhead secondary distribution system of the Company and contracted for by a private Customer. The rating of lamps in lumens is for identification and shall approximate the manufacturer's standard rating. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

A. For each 9,500 lumen (100 watt) high-pressure sodium lamp (51 kWh) .... $~~8~~10.~~81~~40 per lamp. Company will provide lamp, photo-electric relay control equipment, fixture and upsweep arm not over 4 feet in length, and will mount same on an existing pole carrying secondary circuits.

B. Restricted to installations as of February 25, 1993

For each 8150 lumen (175 Watt) mercury vapor lamp (74 kWh).................................. $~~8~~9.~~37~~88 per lamp. Company will provide lamp, photo-electric relay control equipment, fixture and upsweep arm not over 4 feet in length, and will mount same on an existing pole carrying secondary circuits.

C. Restricted to installations as of February 25, 1993

For each 21,500 lumen (400 Watt) mercury vapor lamp (162 kWh).......................... $~~14~~17.~~58~~21 per lamp. Company will provide lamp, photo-electric relay control equipment, fixture and upsweep arm not over 6 feet in length, and will mount same on an existing pole carrying secondary circuits.

D. For each 22,000 lumen (200 watt) high pressure sodium lamp (86 kWh) .... $~~15~~18.~~93~~81 per lamp Company will provide lamp, photo-electric relay control equipment, fixture and upsweep arm not over 6 feet in length, and will mount same on an existing pole carrying secondary circuits.

E. When facilities, in addition to those specified in paragraphs A., B., or C. are required to provide outdoor lighting Service, the Customer will pay in advance the cost of installing all additional facilities. For those facilities installed prior to September 9, 1985, where the Company provided facilities at a monthly rental, such monthly charges will continue at a rate of $~~3~~4.~~60~~25 for each standard distribution wood pole required, $0.~~022~~026 per foot for each foot of span length of wires required and $~~3~~4.~~60~~25 for each KVA of transformer capacity installed.

F. The Customer may elect to own and maintain poles and secondary circuits on their property to accommodate the installation of the outdoor lighting fixture. Such poles and circuits shall meet Company specifications.

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~~Issued October 28, 2021~~ ~~Effective November 1, 2021~~

~~Issued under Order No. 89971 dated October 26, 2021 in Case No. 9490.~~

THE POTOMAC EDISON COMPANY Electric P.S.C. Md. No. 54

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PRIVATE OUTDOOR AREA LIGHTING SERVICE
SCHEDULE "AL"

AVAILABILITY

Available only for installations served prior to September 9, 1985, for lighting Service sold for pole-mounted outdoor area lighting supplied from the existing secondary distribution system of the Company and contracted for by a private Customer. The rating of lamps in lumens is for identification and shall approximate the manufacturer's standard rating. All applicable surcharges, credits and taxes shall apply.

MONTHLY RATE

DISTRIBUTION CHARGES

LIGHTING FIXTURE

Nominal Watts	Nominal Lumens	kWh	Area Lighting (Underground Service)	Floodlighting Overhead or Underground Service
MERCURY VAPOR				
175	8,150	74	$~~14~~16.~~03~~57	
400	21,500	162		$~~17~~20.~~73~~93
1,000	60,000	386		~~22~~26.~~43~~48
HIGH PRESSURE SODIUM				
400	50,000	167		~~23~~27.~~60~~86
QUARTZ IODINE				
500		176		~~18~~21.~~61~~97

POLES

Length	Wood Standard	Wood Other	Metal
14 foot		$~~7~~8.~~42~~76	$ ~~5~~6.~~16~~09
30 foot	$~~3~~4.~~67~~33		~~15~~18.~~40~~18
35 foot	~~5~~6.~~13~~06	~~7~~9.~~81~~22	
40 foot	~~5~~6.~~50~~49		

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PRIVATE OUTDOOR AREA LIGHTING SERVICE
SCHEDULE "AL" (Continued)

OVERHEAD CIRCUIT

$0.~~023~~ 027 per foot for each foot of span length.

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours.. $0.00079 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

ELECTRIC SUPPLY CHARGE

	Summer 06-01-2022 thru 09-30-2022	Non-Summer 10-01-2022 thru 05-31-2023
Energy Charge		
All kilowatt-hours	$0.05417 per kilowatt-hour	$0.05512 per kilowatt-hour

The Transmission and Electric Supply Charges apply only to Customers receiving Type I SOS from the Company. These charges do not apply to Customers obtaining Competitive Power Supply.

LATE PAYMENT

Applies to this schedule as set forth in Company Rule No. 12 of this tariff.

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~~Issued April 21, 2022~~ ~~Effective June 1, 2022~~

~~Approved at Public Service Commission Administrative Meeting of May 25, 2022~~
~~in Case Nos. 8908, 9056, and 9064~~

THE POTOMAC EDISON COMPANY

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PRIVATE OUTDOOR AREA LIGHTING SERVICE
SCHEDULE "AL" (Continued)

GENERAL (Concluded)

When lighting is served from an underground circuit the Customer shall own, install and maintain all necessary concrete bases for poles to be installed in accordance with the Company specifications. The Customer shall also own, install and maintain all facilities including circuits, conduit and pedestals necessary to supply Service to the base of the pole.

CUSTOMER OWNED EQUIPMENT - COMPANY OPERATES AND MAINTAINS

Whenever the Customer furnishes, installs and owns the entire lighting system using equipment approved by and installed in a manner acceptable to the Company, the Company may, at its discretion, operate and maintain the system at the following rates.

DISTRIBUTION CHARGES

LAMP SIZE IN NOMINAL WATTS	KWH	TYPE OF LAMP	TYPE OF FIXTURE BRACKET	TYPE OF FIXTURE POST TOP
250	103	Mercury Vapor	$ 5.~~05~~96	
400	162	" "	~~5~~6.~~47~~46	
1,000	386	" "	~~7~~8.~~61~~99	
400	167	High Pressure Sodium	~~6~~7.~~77~~99	$~~6~~7.~~77~~99

The Company's responsibility under the aforementioned charges for maintaining the Customer owned lighting system is limited to photo control, relamping, cleaning fixtures and painting poles requiring paint. When the Customer's equipment is intermediate in size to those listed above the Customer shall pay the monthly charges applicable to the next larger size.

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THE POTOMAC EDISON COMPANY

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STREET AND HIGHWAY LIGHTING SERVICE
SCHEDULE "MSL"

1. COMPANY OWNED AND MAINTAINED EQUIPMENT

AVAILABILITY

Available for lighting Service sold prior to November 18, 1998 for the lighting of public streets, public highways and other public outdoor areas in municipalities, governmental units and unincorporated communities where such Service can be supplied from the existing general distribution system. All applicable surcharges, credits and taxes shall apply.

This schedule is also applicable within private property which is open to the general public such as private walkways, streets, roads, when the property and buildings are under common ownership and when supply from the Company's distribution system is directly available and when lighting Service is contracted for by the owner thereof. The rating of lamps in lumens is for identification and shall approximate the manufacturer's standard rating.

MONTHLY RATE

DISTRIBUTION CHARGES

Lamp Size			Overhead Supply		Underground Supply Standard Pole		Multiple Units For Each
Nominal Watts	Nominal Lumens	kWh	Wood Pole	Metal Pole	Low Mounting	High Mounting	Additional Fixture Per Pole
High Pressure Sodium							
70	5,800	37	$~~8~~10.~~65~~21		$~~15~~18.~~79~~64	$~~23~~28.~~87~~18	$~~8~~10.~~65~~21
100	9,500	51	~~8~~10.~~56~~11		~~15~~18.~~64~~47	~~23~~28.~~77~~07	~~8~~10.~~56~~11
200	22,000	86	~~13~~15.~~35~~76			~~26~~31.~~57~~37	~~13~~15.~~35~~76
400	50,000	167	~~19~~22.~~00~~43	$~~32~~38.~~22~~04		~~32~~38.~~22~~04	~~19~~22.~~00~~43
High Pressure Sodium - Rectangular Enclosed Fixture							
100	9,500	51				~~37~~43.~~01~~70	~~20~~23.~~16~~80
200	22,000	86				~~37~~44.~~80~~63	~~20~~24.~~99~~78
400	50,000	167				~~36~~42.~~19~~73	~~19~~22.~~37~~87

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STREET AND HIGHWAY LIGHTING SERVICE
SCHEDULE "MSL" (Continued)

MONTHLY RATE (Continued)

DISTRIBUTION CHARGES (Continued)

Lamp Size			Overhead Supply		Underground Supply Standard Pole		Multiple Units For Each
Nominal Watts	Nominal Lumens	Kwh	Wood Pole	Metal Pole	Low Mounting	High Mounting	Additional Fixture Per Pole
Mercury Vapor - Restricted to installations as of February 25, 1993:							
175	8,150	74	$ ~~7~~8.~~40~~74		$~~13~~16.~~97~~49		$ ~~6~~8.~~93~~18
Mercury Vapor - Restricted to installations as of June 14, 1982:							
100	4,000	45	~~8~~9.~~46~~99		~~12~~14.~~20~~40		
250	11,500	103	~~10~~12.~~81~~76			~~24~~29.~~73~~20	
Mercury Vapor - Restricted to installations as of October 17, 1988:							
400	21,500	162	~~10~~12.~~90~~87	~~24~~28.~~51~~94		~~24~~28.~~51~~94	~~10~~12.~~23~~08

All lamps are lighted from dusk to dawn every night, or for approximately 4,200 hours per annum. However, at the request of the Customer individual lamps may be operated continuously 24 hours per day. The monthly rate for each light continuously operated shall be the applicable rate above plus 60% of the base overhead supply wood pole monthly rate.

When the circuit length exceeds 150 feet per light there will be an additional monthly charge of $0.~~022~~ 026 per foot for each foot of span length and $0.~~029~~ 034 per foot for each underground trench foot. (This provision is restricted to locations as of September 9, 1985.)

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STREET AND HIGHWAY LIGHTING SERVICE
SCHEDULE "MSL" (Continued)

MONTHLY RATE

DISTRIBUTION CHARGES

The Company's supply of unmetered energy to the Customer's high pressure sodium street lighting system will be at the following rates:

Lamp Size Nominal Watts	Nominal Lumens	kWh	Monthly Rate
70	5,800	37	$ 3.~~07~~62
100	9,500	51	~~2~~3.~~95~~48
200	22,000	86	~~3~~4.~~60~~25
400	50,000	167	~~6~~7.~~08~~18

When the Customer's equipment is intermediate in size to those listed above, the Customer shall pay the monthly rate applicable to the next larger size.

TRANSMISSION CHARGE

Energy Charge
All kilowatt-hours.. $0.00079 per kilowatt-hour

The Transmission Charge is based on PJM's Open Access Transmission Tariff which will change from time to time and is subject to FERC approval.

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THE POTOMAC EDISON COMPANY

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CO-GENERATION
SCHEDULE "CO-G"

AVAILABILITY

This schedule is applicable for purchases of electricity by the Company from such qualifying facilities (QF) as cogenerators or small power producers as defined in Part 292, Subpart B, of the Public Utility Regulatory Policies Act of 1978 regulations. The Company may require proof that the QF meets the requirements for a qualifying facility under those regulations.

This schedule is available for power to be supplied by the QF to the Company at a single point of delivery in amounts or not more than ~~2~~5,000 kW for qualifying small power producers and 20,000 kW for qualifying cogenerators. .

This schedule may be used in conjunction with any of the Company's filed Rate Schedules presently in effect and applicable to the supply of electric Service to a Customer.

MONTHLY PAYMENTS

Energy Payments:

If applicable, ~~T~~the Company may~~will~~ sell the QF's energy in the PJM hourly real-time energy market provided the QF complies with all PJM requirements to qualify as a PJM generation resource. The Company will pay the QF the PJM real-time locational marginal price (LMP) at the APS Zone, or its successor, for each hour energy is produced and delivered to the Company, less any PJM ancillary charges, other related costs, and Company administrative costs.

Capacity Payments:

If applicable, ~~T~~the Company may~~will~~ offer the QF's capacity in the PJM capacity market provided the QF complies with all PJM requirements to qualify as a PJM capacity resource. The Company will pay the QF the capacity revenues received from PJM, less Company administrative costs, any PJM penalties incurred by the Company as a result of the QF's failure to perform, and other related costs.

CONNECTION CHARGE:

The QF will pay the installed cost of the metering equipment and a monthly charge for the recurring expense of the QF metering connection pursuant to Rule 10 of the Company's Rules and Regulations Covering the Supply of Electric Service.

SIMULTANEOUS PURCHASE AND SALE OPTION

Each QF served under this schedule shall have the option of either a simultaneous purchase and sale or the sale of only its excess power. The selection of such option shall be expressed in an Electric Service Agreement and shall be for a period of not less than one year.

CO-GENERATION
SCHEDULE "CO-G" (Continued)

TERM

One year or longer.

SALES TO QUALIFYING FACILITIES

Supplementary, backup, interruptible, ~~and~~ maintenance, and station power will be supplied by the Company to the QF under the applicable standard Rate Schedules.

INTERCONNECTION COSTS

All interconnection costs including interconnection costs incurred by the Company which are necessary to purchase energy or energy and capacity from the QF or to supply ~~backup~~ power are the responsibility of the QF. The Company will provide a nonbinding estimate of all interconnection costs to be incurred by the Company.

The QF is responsible for providing, installing, owning, and maintaining at its expense all equipment on the QF's side of the interconnection point. The QF must submit its interconnection plans and specifications to the Company, and the Company shall accept or reject those plans. The Company will inspect and approve the installation prior to making the interconnection. The inspection will be conducted by the Company, and the results of the inspection will be provided to the QF. The costs of any additional Company inspection required shall be borne by the QF. The QF is also responsible for obtaining Company approval for equipment and material specifications prior to making any modifications.

(a) The review and/or acceptance by the Company of the application for interconnection or plans and specification for such interconnection submitted by a QF does not and shall not be construed (1) as confirming or endorsing the design of the QF's facilities or (2) as any warranty of safety, durability, or reliability of the facilities.

(b) The Company shall not, by reason of any review or acceptance of the plans and specifications or application for interconnection submitted by QF, be responsible for strength, details of design, adequacy, or capability of the QF's facilities; nor shall the Company's acceptance and/or review of said plans and specifications or application for interconnection be deemed an endorsement or warranty of those facilities.

The Company installs, owns, and maintains at the QF's expense all metering equipment needed to measure separately the electricity delivered to the Company. Access shall be granted by the QF to the Company's authorized representative during any reasonable hours to install, inspect, and maintain the Company's metering equipment.

THE POTOMAC EDISON COMPANY

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ALTERNATIVE GENERATION SCHEDULE
SCHEDULE "AGS" (Continued)

Penalty

The maximum by which the Customer's kilowatt demands exceed the sum of the Customer's firm capacities (i.e., the sum of the Customer's Supplementary, Maintenance, and Standby Firm capacities as applicable) during each interruption period shall be subject to a penalty charge. Only one such penalty shall be assessed per interruption period. The first time that the Customer is notified by the Company to interrupt Service and the Customer fails to reduce load to not more than the sum of its firm capacities, a penalty of $10 per kilowatt shall be applied to those kilowatts in excess of firm capacities. Upon the second occurrence of such a failure to interrupt, a penalty of $10 per kilowatt calculated as set forth above shall be applied and interruptible Service shall not be available to the Customer for the next two years. Upon the third occurrence of such a failure to interrupt, a $10 per kilowatt penalty shall be applied and interruptible Service shall no longer be available to the Customer.

MONTHLY RATE

DISTRIBUTION CHARGE

FIXED DISTRIBUTION CHARGE

$17.00

Demand Charges

Firm Standby Power
All kilowatts..$~~0~~1.~~906~~ 216 per kilowatt

Interruptible Standby Power
All kilowatts..$~~0~~1.~~857~~ 151 per kilowatt

Firm or Interruptible Maintenance Power
All kilowatts..$~~0~~1.~~845~~ 134 per kilowatt

Reactive Kilovolt-Ampere Charge

Reactive kilovolt-ampere charge is applied to the Customer's reactive kilovolt-ampere capacity requirement in excess of 25% of the Customer's kilowatt capacity.

Billing reactive kilovolt-amperes .... $0.40 per reactive kilovolt-ampere

Energy Charge

All kilowatt-hours.. $0.~~00151~~ 00203 per kilowatt-hour

~~ISSUED BY SAMUEL L. BELCHER, PRESIDENT~~

~~Issued October 28, 2021~~ ~~Effective November 1, 2021~~

~~Issued under Order No. 89971 dated October 26, 2021 in Case No. 9490.~~

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THE POTOMAC EDISON COMPANY

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GENERATION STATION POWER
SCHEDULE "SP"

AVAILABILITY

Available to electric generation stations which are owned and/or operated by a qualified member of PJM who are unable to supply station power from other generation stations within PJM. Electric service must be supplied at one point of delivery and the Customer will be responsible for all transforming, controlling, regulating and protective equipment and its operation and maintenance.

MONTHLY BILLING

~~During any PJM billing period in which the Customer's net generation output is positive, the Customer shall pay the Company the Fixed Distribution Charge in accordance with Schedule "G". During any PJM billing period in which the Customer's net generation output is negative, the Customer shall pay the Company a charge based upon all non-Electric Supply Charges for Schedule "G" and any associated Schedule "G" surcharge, and a charge equivalent to the PJM charges incurred by the Company as a result of the Customer's electricity consumption grossed-up for Maryland Gross Receipts Tax and the Commission assessment fee.~~

During any PJM billing period in which the Customer's net generation output is negative, the Customer shall pay the Company a charge based upon all Company Charges for Schedule "G" inclusive of Default Electricity Supply Service. During any PJM billing period in which the Customer's net generation output is positive:

1. Customers receiveing metered Service over 100 kilovolts shall pay the Company the Fixed Distribution Charge in accordance with Schedule "G".
2. Customers receiving metered Service under 100 kilovolts shall pay the Company the Fixed Distribution Charge in accordance with Schedule "G" along with the Distribution Charge portion of Schedule "G" kilowatt demand ratchets during the periods that such ratches are applicable.

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Net generation output is positive when the Customer generates and delivers more power to the Company's electric system than it consumes from the electric system, as measured by the revenue meters.

Net generation output is negative when the Customer consumes more power from the Company's electric system than it generates and delivers to the electric system, as measured by the revenue meters.

ELECTRIC SERVICE AGREEMENT

Electric service hereunder shall be furnished in accordance with an Electric Service Agreement in accordance with the provisions of Schedule "G".

LATE PAYMENT CHARGE

Applies to this schedule as set forth in Company Rule No. 12 of this tariff.

THE POTOMAC EDISON COMPANY - MARYLAND
EDIS Phase II
Summary

EDIS In-Service Capital

EDIS Program	2023	2024	2025	2026	2027
Underground Cable	$ 14,001,859	$ 18,838,900	$ 20,335,550	$ 21,832,200	$ 23,439,000
Recloser	$ 1,701,700	$ -	$ 1,128,400	$ 1,128,400	$ -
Resiliency	$ 2,800,000	$ 2,800,000	$ 2,800,000	$ 2,800,000	$ 2,800,000
Forecasted Annual In-Service Capital	**$ 18,503,559**	**$ 21,638,900**	**$ 24,263,950**	**$ 25,760,600**	**$ 26,239,000**

2024 EDIS Rates[1]

Rate Schedule	Underground Cable	Recloser	Resiliency	Prior Period (Over)/Under Recovery[2]	EDIS Total w/out GRT & Assess. Fee	EDIS Total w/GRT & Assess. Fee
R	0.00035	0.00003	0.00008	$ -	0.00046	**0.00047**
G, C	0.00029	0.00002	0.00007	$ -	0.00038	**0.00039**
C-A, CSH	0.00042	0.00003	0.00010	$ -	0.00055	**0.00056**
PH	0.00023	0.00002	0.00005	$ -	0.00029	**0.00030**
PP	0.00000	0.00000	0.00000	$ -	0.00000	**0.00000**
St Lighting	0.00045	0.00003	0.00010	$ -	0.00058	**0.00059**

Gross Receipts Tax = 2.0%
PSC Assessment Fee = 0.2773%

[1] 2024 rates are estimates and will be updated in a November 2023 filing for rates effective January 2024

[2] Assumed to be zero but will be updated in a November 2023 filing for rates effective January 2024

THE POTOMAC EDISON COMPANY - MARYLAND
EDIS In-Service Capital
Forecasted 2023-2027

EDIS Program	Test Year[1]	January	February	March	April	May	June	July	August	September	October	November	December
Underground Cable	$ 5,122,134												
Test Year $/month (cumulative)		*$ 426,844.50*	*$ 853,689.00*	*$ 1,280,533.50*	*$ 1,707,378.00*	*$ 2,134,222.50*	*$ 2,561,067.00*	*$ 2,987,911.50*	*$ 3,414,756.00*	*$ 3,841,600.50*	*$ 4,268,445.00*	*$ 4,695,289.50*	*$ 5,122,134.00*
2023													
In-Service Capital FERC 3€ U/G Conduit		$ 31,456.26	$ 47,184.39	$ 55,048.46	$ 62,912.52	$ 62,912.52	$ 78,640.66	$ 78,640.66	$ 94,368.79	$ 94,368.79	$ 78,640.66	$ 62,912.52	$ 39,320.33
In-Service Capital FERC 3€ U/G Conduct, Dvcs		$ 470,921.87	$ 706,382.81	$ 824,113.28	$ 941,843.74	$ 941,843.74	$ 1,177,304.67	$ 1,177,304.67	$ 1,412,765.62	$ 1,412,765.62	$ 1,177,304.67	$ 941,843.74	$ 588,652.34
In-Service Capital FERC 3€ Line Transformers		$ 57,696.23	$ 86,544.34	$ 100,968.40	$ 115,392.45	$ 115,392.45	$ 144,240.57	$ 144,240.57	$ 173,088.68	$ 173,088.68	$ 144,240.57	$ 115,392.45	$ 72,120.28
In-Service Capital FERC Total (cumulative)		$ 560,074.36	$ 1,400,185.90	$ 2,380,316.04	$ 3,500,464.75	$ 4,620,613.46	$ 6,020,799.36	$ 7,420,985.26	$ 9,101,208.35	$ 10,781,431.44	$ 12,181,617.34	$ 13,301,766.05	$ 14,001,859.00
Incremental In-Service Capital FERC 366		$ 7,482.78	$ 23,210.91	$ 31,074.98	$ 38,939.04	$ 38,939.04	$ 54,667.17	$ 54,667.17	$ 70,395.31	$ 70,395.31	$ 54,667.17	$ 38,939.04	$ 15,346.85
Incremental In-Service Capital FERC 367		$ 112,022.37	$ 347,483.30	$ 465,213.78	$ 582,944.23	$ 582,944.23	$ 818,405.17	$ 818,405.17	$ 1,053,866.12	$ 1,053,866.12	$ 818,405.17	$ 582,944.23	$ 229,752.83
Incremental In-Service Capital FERC 368		$ 13,724.71	$ 42,572.83	$ 56,996.88	$ 71,420.94	$ 71,420.94	$ 100,269.06	$ 100,269.06	$ 129,117.16	$ 129,117.16	$ 100,269.06	$ 71,420.94	$ 28,148.77
Incremental In-Service Capital FERC Total		$ 133,229.86	$ 413,267.04	$ 553,285.64	$ 693,304.21	$ 693,304.21	$ 973,341.40	$ 973,341.40	$ 1,253,378.59	$ 1,253,378.59	$ 973,341.40	$ 693,304.21	$ 273,248.45
Incremental In-Service Capital (cumulative)		$ 133,229.86	$ 546,496.90	$ 1,099,782.54	$ 1,793,086.75	$ 2,486,390.96	$ 3,459,732.36	$ 4,433,073.76	$ 5,686,452.35	$ 6,939,830.94	$ 7,913,172.34	$ 8,606,476.55	$ 8,879,725.00
2024													
In-Service Capital FERC 3€ U/G Conduit		$ 42,323.05	$ 63,484.57	$ 74,065.34	$ 84,646.09	$ 84,646.09	$ 105,807.63	$ 105,807.63	$ 126,969.15	$ 126,969.15	$ 105,807.63	$ 84,646.09	$ 52,903.82
In-Service Capital FERC 3€ U/G Conduct, Dvcs		$ 633,605.15	$ 950,407.74	$ 1,108,809.03	$ 1,267,210.31	$ 1,267,210.31	$ 1,584,012.88	$ 1,584,012.88	$ 1,900,815.47	$ 1,900,815.47	$ 1,584,012.88	$ 1,267,210.31	$ 792,006.44
In-Service Capital FERC 3€ Line Transformers		$ 77,627.80	$ 116,441.69	$ 135,848.65	$ 155,255.59	$ 155,255.59	$ 194,069.49	$ 194,069.49	$ 232,883.39	$ 232,883.39	$ 194,069.49	$ 155,255.59	$ 97,034.74
In-Service Capital FERC Total (cumulative)		$ 753,556.00	$ 1,883,890.00	$ 3,202,613.01	$ 4,709,725.00	$ 6,216,836.99	$ 8,100,726.99	$ 9,984,616.99	$ 12,245,285.00	$ 14,505,953.01	$ 16,389,843.01	$ 17,896,955.00	$ 18,838,900.00
Incremental In-Service Capital FERC 366		$ 18,349.57	$ 39,511.09	$ 50,091.85	$ 60,672.61	$ 60,672.61	$ 81,834.14	$ 81,834.14	$ 102,995.67	$ 102,995.67	$ 81,834.14	$ 60,672.62	$ 28,930.33
Incremental In-Service Capital FERC 367		$ 274,705.65	$ 591,508.23	$ 749,909.53	$ 908,310.79	$ 908,310.80	$ 1,225,113.38	$ 1,225,113.38	$ 1,541,915.97	$ 1,541,915.97	$ 1,225,113.38	$ 908,310.79	$ 433,106.94
Incremental In-Service Capital FERC 368		$ 33,656.28	$ 72,470.18	$ 91,877.13	$ 111,284.09	$ 111,284.08	$ 150,097.98	$ 150,097.98	$ 188,911.87	$ 188,911.87	$ 150,097.98	$ 111,284.08	$ 53,063.23
Incremental In-Service Capital FERC Total		$ 326,711.50	$ 703,489.50	$ 891,878.51	$ 1,080,267.49	$ 1,080,267.49	$ 1,457,045.50	$ 1,457,045.50	$ 1,833,823.51	$ 1,833,823.51	$ 1,457,045.50	$ 1,080,267.49	$ 515,100.50
Incremental In-Service Capital (cumulative)		$ 326,711.50	$ 1,030,201.00	$ 1,922,079.51	$ 3,002,347.00	$ 4,082,614.49	$ 5,539,659.99	$ 6,996,705.49	$ 8,830,529.00	$ 10,664,352.51	$ 12,121,398.01	$ 13,201,665.50	$ 13,716,766.00
2025													
In-Service Capital FERC 3€ U/G Conduit		$ 45,685.39	$ 68,528.08	$ 79,949.43	$ 91,370.77	$ 91,370.77	$ 114,213.48	$ 114,213.48	$ 137,056.18	$ 137,056.18	$ 114,213.48	$ 91,370.77	$ 57,106.74
In-Service Capital FERC 3€ U/G Conduct, Dvcs		$ 683,941.70	$ 1,025,912.56	$ 1,196,897.98	$ 1,367,883.40	$ 1,367,883.40	$ 1,709,854.24	$ 1,709,854.24	$ 2,051,825.11	$ 2,051,825.11	$ 1,709,854.24	$ 1,367,883.40	$ 854,927.13
In-Service Capital FERC 3€ Line Transformers		$ 83,794.91	$ 125,692.36	$ 146,641.10	$ 167,589.81	$ 167,589.81	$ 209,487.28	$ 209,487.28	$ 251,384.73	$ 251,384.73	$ 209,487.28	$ 167,589.81	$ 104,743.63
In-Service Capital FERC Total (cumulative)		$ 813,422.00	$ 2,033,555.00	$ 3,457,043.51	$ 5,083,887.50	$ 6,710,731.49	$ 8,744,286.49	$ 10,777,841.49	$ 13,218,107.50	$ 15,658,373.51	$ 17,691,928.51	$ 19,318,772.50	$ 20,335,550.00
Incremental In-Service Capital FERC 366		$ 21,711.91	$ 44,554.60	$ 55,975.95	$ 67,397.29	$ 67,397.29	$ 90,239.99	$ 90,239.99	$ 113,082.69	$ 113,082.69	$ 90,239.99	$ 67,397.30	$ 33,133.26
Incremental In-Service Capital FERC 367		$ 325,042.19	$ 667,013.05	$ 837,998.48	$ 1,008,983.89	$ 1,008,983.89	$ 1,350,954.75	$ 1,350,954.75	$ 1,692,925.61	$ 1,692,925.61	$ 1,350,954.74	$ 1,008,983.88	$ 496,027.62
Incremental In-Service Capital FERC 368		$ 39,823.40	$ 81,720.85	$ 102,669.58	$ 123,618.31	$ 123,618.31	$ 165,515.76	$ 165,515.76	$ 207,413.21	$ 207,413.21	$ 165,515.77	$ 123,618.31	$ 60,772.12
Incremental In-Service Capital FERC Total		$ 386,577.50	$ 793,288.50	$ 996,644.01	$ 1,199,999.49	$ 1,199,999.49	$ 1,606,710.50	$ 1,606,710.50	$ 2,013,421.51	$ 2,013,421.51	$ 1,606,710.50	$ 1,199,999.49	$ 589,933.00
Incremental In-Service Capital (cumulative)		$ 386,577.50	$ 1,179,866.00	$ 2,176,510.01	$ 3,376,509.50	$ 4,576,508.99	$ 6,183,219.49	$ 7,789,929.99	$ 9,803,351.50	$ 11,816,773.01	$ 13,423,483.51	$ 14,623,483.00	$ 15,213,416.00
2026													
In-Service Capital FERC 3€ U/G Conduit		$ 49,047.73	$ 73,571.59	$ 85,833.53	$ 98,095.45	$ 98,095.45	$ 122,619.33	$ 122,619.33	$ 147,143.20	$ 147,143.20	$ 122,619.33	$ 98,095.45	$ 61,309.67
In-Service Capital FERC 3€ U/G Conduct, Dvcs		$ 734,278.24	$ 1,101,417.37	$ 1,284,986.94	$ 1,468,556.49	$ 1,468,556.49	$ 1,835,695.60	$ 1,835,695.60	$ 2,202,834.75	$ 2,202,834.75	$ 1,835,695.60	$ 1,468,556.49	$ 917,847.81
In-Service Capital FERC 3€ Line Transformers		$ 89,962.03	$ 134,943.03	$ 157,433.55	$ 179,924.04	$ 179,924.04	$ 224,905.06	$ 224,905.06	$ 269,886.07	$ 269,886.07	$ 224,905.06	$ 179,924.04	$ 112,452.52
In-Service Capital FERC Total (cumulative)		$ 873,288.00	$ 2,183,220.00	$ 3,711,474.02	$ 5,458,050.00	$ 7,204,625.98	$ 9,387,845.98	$ 11,571,065.98	$ 14,190,930.00	$ 16,810,794.02	$ 18,994,014.02	$ 20,740,590.00	$ 21,832,200.00
Incremental In-Service Capital FERC 366		$ 25,074.25	$ 49,598.11	$ 61,860.05	$ 74,121.98	$ 74,121.97	$ 98,645.84	$ 98,645.84	$ 123,169.71	$ 123,169.71	$ 98,645.85	$ 74,121.98	$ 37,336.18
Incremental In-Service Capital FERC 367		$ 375,378.74	$ 742,517.87	$ 926,087.44	$ 1,109,656.98	$ 1,109,656.98	$ 1,476,796.11	$ 1,476,796.11	$ 1,843,935.25	$ 1,843,935.25	$ 1,476,796.11	$ 1,109,656.97	$ 558,948.30
Incremental In-Service Capital FERC 368		$ 45,990.51	$ 90,971.52	$ 113,462.03	$ 135,952.52	$ 135,952.53	$ 180,933.55	$ 180,933.55	$ 225,914.56	$ 225,914.56	$ 180,933.54	$ 135,952.53	$ 68,481.02
Incremental In-Service Capital FERC Total		$ 446,443.50	$ 883,087.50	$ 1,101,409.52	$ 1,319,731.48	$ 1,319,731.48	$ 1,756,375.50	$ 1,756,375.50	$ 2,193,019.52	$ 2,193,019.52	$ 1,756,375.50	$ 1,319,731.48	$ 664,765.50
Incremental In-Service Capital (cumulative)		$ 446,443.50	$ 1,329,531.00	$ 2,430,940.52	$ 3,750,672.00	$ 5,070,403.48	$ 6,826,778.98	$ 8,583,154.48	$ 10,776,174.00	$ 12,969,193.52	$ 14,725,569.02	$ 16,045,300.50	$ 16,710,066.00
2027													
In-Service Capital FERC 3€ U/G Conduit		$ 52,657.53	$ 78,986.29	$ 92,150.68	$ 105,315.06	$ 105,315.06	$ 131,643.84	$ 131,643.84	$ 157,972.60	$ 157,972.60	$ 131,643.84	$ 105,315.06	$ 65,821.92
In-Service Capital FERC 3€ U/G Conduct, Dvcs		$ 788,319.44	$ 1,182,479.18	$ 1,379,559.04	$ 1,576,638.89	$ 1,576,638.89	$ 1,970,798.60	$ 1,970,798.60	$ 2,364,958.35	$ 2,364,958.35	$ 1,970,798.60	$ 1,576,638.89	$ 985,399.31
In-Service Capital FERC 3€ Line Transformers		$ 96,583.03	$ 144,874.53	$ 169,020.29	$ 193,166.04	$ 193,166.04	$ 241,457.56	$ 241,457.56	$ 289,749.07	$ 289,749.07	$ 241,457.56	$ 193,166.04	$ 120,728.77
In-Service Capital FERC Total (cumulative)		$ 937,560.00	$ 2,343,900.00	$ 3,984,630.02	$ 5,859,750.00	$ 7,734,869.98	$ 10,078,769.98	$ 12,422,669.98	$ 15,235,350.00	$ 18,048,030.02	$ 20,391,930.02	$ 22,267,050.00	$ 23,439,000.00
Incremental In-Service Capital FERC 366		$ 28,684.05	$ 55,012.81	$ 68,177.20	$ 81,341.58	$ 81,341.58	$ 107,670.34	$ 107,670.35	$ 133,999.11	$ 133,999.11	$ 107,670.35	$ 81,341.58	$ 41,848.43
Incremental In-Service Capital FERC 367		$ 429,419.94	$ 823,579.67	$ 1,020,659.54	$ 1,217,739.38	$ 1,217,739.38	$ 1,611,899.11	$ 1,611,899.11	$ 2,006,058.85	$ 2,006,058.85	$ 1,611,899.11	$ 1,217,739.37	$ 626,499.80
Incremental In-Service Capital FERC 368		$ 52,611.51	$ 100,903.02	$ 125,048.78	$ 149,194.52	$ 149,194.52	$ 197,486.05	$ 197,486.04	$ 245,777.56	$ 245,777.56	$ 197,486.04	$ 149,194.53	$ 76,757.27
Incremental In-Service Capital FERC Total		$ 510,715.50	$ 979,495.50	$ 1,213,885.52	$ 1,448,275.48	$ 1,448,275.48	$ 1,917,055.50	$ 1,917,055.50	$ 2,385,835.52	$ 2,385,835.52	$ 1,917,055.50	$ 1,448,275.48	$ 745,105.50
Incremental In-Service Capital (cumulative)		$ 510,715.50	$ 1,490,211.00	$ 2,704,096.52	$ 4,152,372.00	$ 5,600,647.48	$ 7,517,702.98	$ 9,434,758.48	$ 11,820,594.00	$ 14,206,429.52	$ 16,123,485.02	$ 17,571,760.50	$ 18,316,866.00

THE POTOMAC EDISON COMPANY - MARYLAND
EDIS In-Service Capital
Forecasted 2023-2027

EDIS Program	Test Year[1]	January	February	March	April	May	June	July	August	September	October	November	December
Recloser	$ 316,779												
Test Year $/month (cumulative)		*$ 26,398.25*	*$ 52,796.50*	*$ 79,194.75*	*$ 105,593.00*	*$ 131,991.25*	*$ 158,389.50*	*$ 184,787.75*	*$ 211,186.00*	*$ 237,584.25*	*$ 263,982.50*	*$ 290,380.75*	*$ 316,779.00*
2023													
In-Service Capital FERC 36 Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ 453,786.67	$ 340,340.00	$ 340,340.00	$ 340,340.00	$ 113,446.67	$ 113,446.67
In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ -	$ 453,786.67	$ 794,126.67	$ 1,134,466.67	$ 1,474,806.67	$ 1,588,253.33	$ 1,701,700.00
Incremental In-Service Capital FERC 362		$ -	$ -	$ -	$ -	$ -	$ -	$ 268,998.92	$ 313,941.75	$ 313,941.75	$ 313,941.75	$ 87,048.42	$ 87,048.42
Incremental In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ -	$ 268,998.92	$ 582,940.67	$ 896,882.42	$ 1,210,824.17	$ 1,297,872.58	$ 1,384,921.00
2024													
In-Service Capital FERC 36 Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental In-Service Capital FERC 362		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2025													
In-Service Capital FERC 36 Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ 300,906.67	$ 225,680.00	$ 225,680.00	$ 225,680.00	$ 75,226.67	$ 75,226.67
In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ -	$ 300,906.67	$ 526,586.67	$ 752,266.67	$ 977,946.67	$ 1,053,173.33	$ 1,128,400.00
Incremental In-Service Capital FERC 362		$ -	$ -	$ -	$ -	$ -	$ -	$ 116,118.92	$ 199,281.75	$ 199,281.75	$ 199,281.75	$ 48,828.42	$ 48,828.42
Incremental In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ -	$ 116,118.92	$ 315,400.67	$ 514,682.42	$ 713,964.17	$ 762,792.58	$ 811,621.00
2026													
In-Service Capital FERC 36 Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ 300,906.67	$ 225,680.00	$ 225,680.00	$ 225,680.00	$ 75,226.67	$ 75,226.67
In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ -	$ 300,906.67	$ 526,586.67	$ 752,266.67	$ 977,946.67	$ 1,053,173.33	$ 1,128,400.00
Incremental In-Service Capital FERC 362		$ -	$ -	$ -	$ -	$ -	$ -	$ 116,118.92	$ 199,281.75	$ 199,281.75	$ 199,281.75	$ 48,828.42	$ 48,828.42
Incremental In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ -	$ 116,118.92	$ 315,400.67	$ 514,682.42	$ 713,964.17	$ 762,792.58	$ 811,621.00
2027													
In-Service Capital FERC 36 Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental In-Service Capital FERC 362		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

THE POTOMAC EDISON COMPANY - MARYLAND
EDIS In-Service Capital
Forecasted 2023-2027

EDIS Program	Test Year[1]	January	February	March	April	May	June	July	August	September	October	November	December
Resiliency	$ -												
formerly Distribution Automation													
Test Year $/month (cumulative)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023													
In-Service Capital FERC 36 Station Equipment		$ -	$ -	$ -	$ -	$ -	$ 185.23	$ 185.23	$ 555.69	$ 370.46	$ 370.46	$ 185.23	$ -
In-Service Capital FERC 36 Pole, Tower, Fixture		$ -	$ -	$ -	$ -	$ -	$ 38,996.28	$ 38,996.28	$ 116,988.83	$ 77,992.55	$ 77,992.55	$ 38,996.28	$ -
In-Service Capital FERC 36 O/H Conduct, Dvcs		$ -	$ -	$ -	$ -	$ -	$ 220,987.09	$ 220,987.09	$ 662,961.28	$ 441,974.19	$ 441,974.19	$ 220,987.09	$ -
In-Service Capital FERC 36 U/G Conduit		$ -	$ -	$ -	$ -	$ -	$ 111.09	$ 111.09	$ 333.27	$ 222.18	$ 222.18	$ 111.09	$ -
In-Service Capital FERC 36 U/G Conduct, Dvcs		$ -	$ -	$ -	$ -	$ -	$ 580.26	$ 580.26	$ 1,740.78	$ 1,160.52	$ 1,160.52	$ 580.26	$ -
In-Service Capital FERC 36 Line Transformers		$ -	$ -	$ -	$ -	$ -	$ 18,886.27	$ 18,886.27	$ 56,658.81	$ 37,772.54	$ 37,772.54	$ 18,886.27	$ -
In-Service Capital FERC 36 Services		$ -	$ -	$ -	$ -	$ -	$ 253.78	$ 253.78	$ 761.34	$ 507.56	$ 507.56	$ 253.78	$ -
In-Service Capital FERC 39 Comm Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 560,000.00	$ 1,400,000.00	$ 1,960,000.00	$ 2,520,000.00	$ 2,800,000.00	$ 2,800,000.00
Incremental In-Service Capital FERC 362		$ -	$ -	$ -	$ -	$ -	$ 185.23	$ 185.23	$ 555.69	$ 370.46	$ 370.46	$ 185.23	$ -
Incremental In-Service Capital FERC 364		$ -	$ -	$ -	$ -	$ -	$ 38,996.28	$ 38,996.28	$ 116,988.83	$ 77,992.55	$ 77,992.55	$ 38,996.28	$ -
Incremental In-Service Capital FERC 365		$ -	$ -	$ -	$ -	$ -	$ 220,987.09	$ 220,987.09	$ 662,961.28	$ 441,974.19	$ 441,974.19	$ 220,987.09	$ -
Incremental In-Service Capital FERC 366		$ -	$ -	$ -	$ -	$ -	$ 111.09	$ 111.09	$ 333.27	$ 222.18	$ 222.18	$ 111.09	$ -
Incremental In-Service Capital FERC 367		$ -	$ -	$ -	$ -	$ -	$ 580.26	$ 580.26	$ 1,740.78	$ 1,160.52	$ 1,160.52	$ 580.26	$ -
Incremental In-Service Capital FERC 368		$ -	$ -	$ -	$ -	$ -	$ 18,886.27	$ 18,886.27	$ 56,658.81	$ 37,772.54	$ 37,772.54	$ 18,886.27	$ -
Incremental In-Service Capital FERC 369		$ -	$ -	$ -	$ -	$ -	$ 253.78	$ 253.78	$ 761.34	$ 507.56	$ 507.56	$ 253.78	$ -
Incremental In-Service Capital FERC 397		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental In-Service Capital FERC Total		$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 280,000.00	$ 840,000.00	$ 560,000.00	$ 560,000.00	$ 280,000.00	$ -
Incremental In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 560,000.00	$ 1,400,000.00	$ 1,960,000.00	$ 2,520,000.00	$ 2,800,000.00	$ 2,800,000.00
2024													
In-Service Capital FERC 36 Station Equipment		$ -	$ -	$ -	$ -	$ -	$ 185.23	$ 185.23	$ 555.69	$ 370.46	$ 370.46	$ 185.23	$ -
In-Service Capital FERC 36 Pole, Tower, Fixture		$ -	$ -	$ -	$ -	$ -	$ 38,996.28	$ 38,996.28	$ 116,988.83	$ 77,992.55	$ 77,992.55	$ 38,996.28	$ -
In-Service Capital FERC 36 O/H Conduct, Dvcs		$ -	$ -	$ -	$ -	$ -	$ 220,987.09	$ 220,987.09	$ 662,961.28	$ 441,974.19	$ 441,974.19	$ 220,987.09	$ -
In-Service Capital FERC 36 U/G Conduit		$ -	$ -	$ -	$ -	$ -	$ 111.09	$ 111.09	$ 333.27	$ 222.18	$ 222.18	$ 111.09	$ -
In-Service Capital FERC 36 U/G Conduct, Dvcs		$ -	$ -	$ -	$ -	$ -	$ 580.26	$ 580.26	$ 1,740.78	$ 1,160.52	$ 1,160.52	$ 580.26	$ -
In-Service Capital FERC 36 Line Transformers		$ -	$ -	$ -	$ -	$ -	$ 18,886.27	$ 18,886.27	$ 56,658.81	$ 37,772.54	$ 37,772.54	$ 18,886.27	$ -
In-Service Capital FERC 36 Services		$ -	$ -	$ -	$ -	$ -	$ 253.78	$ 253.78	$ 761.34	$ 507.56	$ 507.56	$ 253.78	$ -
In-Service Capital FERC 39 Comm Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 560,000.00	$ 1,400,000.00	$ 1,960,000.00	$ 2,520,000.00	$ 2,800,000.00	$ 2,800,000.00
Incremental In-Service Capital FERC 362		$ -	$ -	$ -	$ -	$ -	$ 185.23	$ 185.23	$ 555.69	$ 370.46	$ 370.46	$ 185.23	$ -
Incremental In-Service Capital FERC 364		$ -	$ -	$ -	$ -	$ -	$ 38,996.28	$ 38,996.28	$ 116,988.83	$ 77,992.55	$ 77,992.55	$ 38,996.28	$ -
Incremental In-Service Capital FERC 365		$ -	$ -	$ -	$ -	$ -	$ 220,987.09	$ 220,987.09	$ 662,961.28	$ 441,974.19	$ 441,974.19	$ 220,987.09	$ -
Incremental In-Service Capital FERC 366		$ -	$ -	$ -	$ -	$ -	$ 111.09	$ 111.09	$ 333.27	$ 222.18	$ 222.18	$ 111.09	$ -
Incremental In-Service Capital FERC 367		$ -	$ -	$ -	$ -	$ -	$ 580.26	$ 580.26	$ 1,740.78	$ 1,160.52	$ 1,160.52	$ 580.26	$ -
Incremental In-Service Capital FERC 368		$ -	$ -	$ -	$ -	$ -	$ 18,886.27	$ 18,886.27	$ 56,658.81	$ 37,772.54	$ 37,772.54	$ 18,886.27	$ -
Incremental In-Service Capital FERC 369		$ -	$ -	$ -	$ -	$ -	$ 253.78	$ 253.78	$ 761.34	$ 507.56	$ 507.56	$ 253.78	$ -
Incremental In-Service Capital FERC 397		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental In-Service Capital FERC Total		$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 280,000.00	$ 840,000.00	$ 560,000.00	$ 560,000.00	$ 280,000.00	$ -
Incremental In-Service Capital (cumulative)		$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 560,000.00	$ 1,400,000.00	$ 1,960,000.00	$ 2,520,000.00	$ 2,800,000.00	$ 2,800,000.00

THE POTOMAC EDISON COMPANY - MARYLAND
EDIS In-Service Capital
Forecasted 2023-2027

2025												
In-Service Capital FERC 36 Station Equipment	$ -	$ -	$ -	$ -	$ -	$ 185.23	$ 185.23	$ 555.69	$ 370.46	$ 370.46	$ 185.23	$ -
In-Service Capital FERC 36 Pole, Tower, Fixture	$ -	$ -	$ -	$ -	$ -	$ 38,996.28	$ 38,996.28	$ 116,988.83	$ 77,992.55	$ 77,992.55	$ 38,996.28	$ -
In-Service Capital FERC 36 O/H Conduct, Dvcs	$ -	$ -	$ -	$ -	$ -	$ 220,987.09	$ 220,987.09	$ 662,961.28	$ 441,974.19	$ 441,974.19	$ 220,987.09	$ -
In-Service Capital FERC 36 U/G Conduit	$ -	$ -	$ -	$ -	$ -	$ 111.09	$ 111.09	$ 333.27	$ 222.18	$ 222.18	$ 111.09	$ -
In-Service Capital FERC 36 U/G Conduct, Dvcs	$ -	$ -	$ -	$ -	$ -	$ 580.26	$ 580.26	$ 1,740.78	$ 1,160.52	$ 1,160.52	$ 580.26	$ -
In-Service Capital FERC 36 Line Transformers	$ -	$ -	$ -	$ -	$ -	$ 18,886.27	$ 18,886.27	$ 56,658.81	$ 37,772.54	$ 37,772.54	$ 18,886.27	$ -
In-Service Capital FERC 36 Services	$ -	$ -	$ -	$ -	$ -	$ 253.78	$ 253.78	$ 761.34	$ 507.56	$ 507.56	$ 253.78	$ -
In-Service Capital FERC 39 Comm Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
In-Service Capital (cumulative)	$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 560,000.00	$ 1,400,000.00	$ 1,960,000.00	$ 2,520,000.00	$ 2,800,000.00	$ 2,800,000.00
Incremental In-Service Capital FERC 362	$ -	$ -	$ -	$ -	$ -	$ 185.23	$ 185.23	$ 555.69	$ 370.46	$ 370.46	$ 185.23	$ -
Incremental In-Service Capital FERC 364	$ -	$ -	$ -	$ -	$ -	$ 38,996.28	$ 38,996.28	$ 116,988.83	$ 77,992.55	$ 77,992.55	$ 38,996.28	$ -
Incremental In-Service Capital FERC 365	$ -	$ -	$ -	$ -	$ -	$ 220,987.09	$ 220,987.09	$ 662,961.28	$ 441,974.19	$ 441,974.19	$ 220,987.09	$ -
Incremental In-Service Capital FERC 366	$ -	$ -	$ -	$ -	$ -	$ 111.09	$ 111.09	$ 333.27	$ 222.18	$ 222.18	$ 111.09	$ -
Incremental In-Service Capital FERC 367	$ -	$ -	$ -	$ -	$ -	$ 580.26	$ 580.26	$ 1,740.78	$ 1,160.52	$ 1,160.52	$ 580.26	$ -
Incremental In-Service Capital FERC 368	$ -	$ -	$ -	$ -	$ -	$ 18,886.27	$ 18,886.27	$ 56,658.81	$ 37,772.54	$ 37,772.54	$ 18,886.27	$ -
Incremental In-Service Capital FERC 369	$ -	$ -	$ -	$ -	$ -	$ 253.78	$ 253.78	$ 761.34	$ 507.56	$ 507.56	$ 253.78	$ -
Incremental In-Service Capital FERC 397	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental In-Service Capital FERC Total	$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 280,000.00	$ 840,000.00	$ 560,000.00	$ 560,000.00	$ 280,000.00	$ -
Incremental In-Service Capital (cumulative)	$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 560,000.00	$ 1,400,000.00	$ 1,960,000.00	$ 2,520,000.00	$ 2,800,000.00	$ 2,800,000.00
2026												
In-Service Capital FERC 36 Station Equipment	$ -	$ -	$ -	$ -	$ -	$ 185.23	$ 185.23	$ 555.69	$ 370.46	$ 370.46	$ 185.23	$ -
In-Service Capital FERC 36 Pole, Tower, Fixture	$ -	$ -	$ -	$ -	$ -	$ 38,996.28	$ 38,996.28	$ 116,988.83	$ 77,992.55	$ 77,992.55	$ 38,996.28	$ -
In-Service Capital FERC 36 O/H Conduct, Dvcs	$ -	$ -	$ -	$ -	$ -	$ 220,987.09	$ 220,987.09	$ 662,961.28	$ 441,974.19	$ 441,974.19	$ 220,987.09	$ -
In-Service Capital FERC 36 U/G Conduit	$ -	$ -	$ -	$ -	$ -	$ 111.09	$ 111.09	$ 333.27	$ 222.18	$ 222.18	$ 111.09	$ -
In-Service Capital FERC 36 U/G Conduct, Dvcs	$ -	$ -	$ -	$ -	$ -	$ 580.26	$ 580.26	$ 1,740.78	$ 1,160.52	$ 1,160.52	$ 580.26	$ -
In-Service Capital FERC 36 Line Transformers	$ -	$ -	$ -	$ -	$ -	$ 18,886.27	$ 18,886.27	$ 56,658.81	$ 37,772.54	$ 37,772.54	$ 18,886.27	$ -
In-Service Capital FERC 36 Services	$ -	$ -	$ -	$ -	$ -	$ 253.78	$ 253.78	$ 761.34	$ 507.56	$ 507.56	$ 253.78	$ -
In-Service Capital FERC 39 Comm Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
In-Service Capital (cumulative)	$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 560,000.00	$ 1,400,000.00	$ 1,960,000.00	$ 2,520,000.00	$ 2,800,000.00	$ 2,800,000.00
Incremental In-Service Capital FERC 362	$ -	$ -	$ -	$ -	$ -	$ 185.23	$ 185.23	$ 555.69	$ 370.46	$ 370.46	$ 185.23	$ -
Incremental In-Service Capital FERC 364	$ -	$ -	$ -	$ -	$ -	$ 38,996.28	$ 38,996.28	$ 116,988.83	$ 77,992.55	$ 77,992.55	$ 38,996.28	$ -
Incremental In-Service Capital FERC 365	$ -	$ -	$ -	$ -	$ -	$ 220,987.09	$ 220,987.09	$ 662,961.28	$ 441,974.19	$ 441,974.19	$ 220,987.09	$ -
Incremental In-Service Capital FERC 366	$ -	$ -	$ -	$ -	$ -	$ 111.09	$ 111.09	$ 333.27	$ 222.18	$ 222.18	$ 111.09	$ -
Incremental In-Service Capital FERC 367	$ -	$ -	$ -	$ -	$ -	$ 580.26	$ 580.26	$ 1,740.78	$ 1,160.52	$ 1,160.52	$ 580.26	$ -
Incremental In-Service Capital FERC 368	$ -	$ -	$ -	$ -	$ -	$ 18,886.27	$ 18,886.27	$ 56,658.81	$ 37,772.54	$ 37,772.54	$ 18,886.27	$ -
Incremental In-Service Capital FERC 369	$ -	$ -	$ -	$ -	$ -	$ 253.78	$ 253.78	$ 761.34	$ 507.56	$ 507.56	$ 253.78	$ -
Incremental In-Service Capital FERC 397	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental In-Service Capital FERC Total	$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 280,000.00	$ 840,000.00	$ 560,000.00	$ 560,000.00	$ 280,000.00	$ -
Incremental In-Service Capital (cumulative)	$ -	$ -	$ -	$ -	$ -	$ 280,000.00	$ 560,000.00	$ 1,400,000.00	$ 1,960,000.00	$ 2,520,000.00	$ 2,800,000.00	$ 2,800,000.00
2027												
In-Service Capital FERC 36 Station Equipment	$ -	$ -	$ -	$ -	$ -	$ 185.23	$ 185.23	$ 555.69	$ 370.46	$ 370.46	$ 185.23	$ -

THE POTOMAC EDISON COMPANY - MARYLAND
Underground Cable Revenue Requirement Calculation
U/G Conduit

Reg Depreciation	1.43%	FERC Account 366 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	1.62%	FERC Account 366 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	*[b]*	*[c]*	*[d]*	*[e]*	*[f]*	*[g]=[d]-[f]*	*[n]*	*[o]=[g]+[n]*	*[p]=[e]*	*[q]*	*[r]=[p]+[q]*
2023	Jan-23	$ 7,482.78	$ 7,482.78	$ 4.46	$ 4.46	$ 7,478.32	$ (5.21)	$ 7,473.11	$ 4.46	$ 56.59	$ 61.05
	Feb-23	$ 23,210.91	$ 30,693.69	$ 22.75	$ 27.21	$ 30,666.48	$ (27.16)	$ 30,639.32	$ 22.75	$ 232.00	$ 254.75
	Mar-23	$ 31,074.98	$ 61,768.67	$ 55.09	$ 82.30	$ 61,686.37	$ (72.27)	$ 61,614.10	$ 55.09	$ 466.53	$ 521.62
	Apr-23	$ 38,939.04	$ 100,707.71	$ 96.81	$ 179.11	$ 100,528.60	$ (150.55)	$ 100,378.05	$ 96.81	$ 760.04	$ 856.85
	May-23	$ 38,939.04	$ 139,646.75	$ 143.21	$ 322.32	$ 139,324.43	$ (266.29)	$ 139,058.14	$ 143.21	$ 1,052.92	$ 1,196.13
	Jun-23	$ 54,667.17	$ 194,313.92	$ 198.98	$ 521.30	$ 193,792.62	$ (447.27)	$ 193,345.35	$ 198.98	$ 1,463.98	$ 1,662.96
	Jul-23	$ 54,667.17	$ 248,981.09	$ 264.13	$ 785.43	$ 248,195.66	$ (704.34)	$ 247,491.32	$ 264.13	$ 1,873.96	$ 2,138.09
	Aug-23	$ 70,395.31	$ 319,376.40	$ 338.65	$ 1,124.08	$ 318,252.32	$ (1,086.19)	$ 317,166.13	$ 338.65	$ 2,401.52	$ 2,740.17
	Sep-23	$ 70,395.31	$ 389,771.71	$ 422.53	$ 1,546.61	$ 388,225.10	$ (1,626.56)	$ 386,598.54	$ 422.53	$ 2,927.25	$ 3,349.78
	Oct-23	$ 54,667.17	$ 444,438.88	$ 497.05	$ 2,043.66	$ 442,395.22	$ (2,334.46)	$ 440,060.76	$ 497.05	$ 3,332.06	$ 3,829.11
	Nov-23	$ 38,939.04	$ 483,377.92	$ 626.28	$ 2,669.94	$ 480,707.98	$ (3,207.71)	$ 477,500.27	$ 626.28	$ 3,858.12	$ 4,484.40
	Dec-23	$ 15,346.85	$ 498,724.77	$ 662.92	$ 3,332.86	$ 495,391.91	$ (4,229.24)	$ 491,162.67	$ 662.92	$ 3,968.51	$ 4,631.43
2024	Jan-24	$ 18,349.57	$ 517,074.34	$ 685.66	$ 4,018.52	$ 513,055.82	$ (4,881.94)	$ 508,173.88	$ 685.66	$ 4,105.96	$ 4,791.62
	Feb-24	$ 39,511.09	$ 556,585.43	$ 724.72	$ 4,743.24	$ 551,842.19	$ (5,560.95)	$ 546,281.24	$ 724.72	$ 4,413.86	$ 5,138.58
	Mar-24	$ 50,091.85	$ 606,677.28	$ 785.20	$ 5,528.44	$ 601,148.84	$ (6,275.01)	$ 594,873.83	$ 785.20	$ 4,806.48	$ 5,591.68
	Apr-24	$ 60,672.61	$ 667,349.89	$ 859.97	$ 6,388.41	$ 660,961.48	$ (7,038.06)	$ 653,923.42	$ 859.97	$ 5,283.59	$ 6,143.56
	May-24	$ 60,672.61	$ 728,022.50	$ 941.88	$ 7,330.29	$ 720,692.21	$ (7,856.83)	$ 712,835.38	$ 941.88	$ 5,759.58	$ 6,701.46
	Jun-24	$ 81,834.14	$ 809,856.64	$ 1,038.07	$ 8,368.36	$ 801,488.28	$ (8,769.77)	$ 792,718.51	$ 1,038.07	$ 6,405.03	$ 7,443.10
	Jul-24	$ 81,834.14	$ 891,690.78	$ 1,148.54	$ 9,516.90	$ 882,173.88	$ (9,793.05)	$ 872,380.83	$ 1,148.54	$ 7,048.68	$ 8,197.22
	Aug-24	$ 102,995.67	$ 994,686.45	$ 1,273.30	$ 10,790.20	$ 983,896.25	$ (10,994.56)	$ 972,901.69	$ 1,273.30	$ 7,860.88	$ 9,134.18
	Sep-24	$ 102,995.67	$ 1,097,682.12	$ 1,412.35	$ 12,202.55	$ 1,085,479.57	$ (12,423.51)	$ 1,073,056.06	$ 1,412.35	$ 8,670.10	$ 10,082.45
	Oct-24	$ 81,834.14	$ 1,179,516.26	$ 1,537.11	$ 13,739.66	$ 1,165,776.60	$ (14,099.62)	$ 1,151,676.98	$ 1,537.11	$ 9,305.35	$ 10,842.46
	Nov-24	$ 60,672.62	$ 1,240,188.88	$ 1,633.30	$ 15,372.96	$ 1,224,815.92	$ (16,062.30)	$ 1,208,753.62	$ 1,633.30	$ 9,766.52	$ 11,399.82
	Dec-24	$ 28,930.33	$ 1,269,119.21	$ 1,693.78	$ 17,066.74	$ 1,252,052.47	$ (18,306.87)	$ 1,233,745.60	$ 1,693.78	$ 9,968.45	$ 11,662.23
2025	Jan-25	$ 21,711.91	$ 1,290,831.12	$ 1,727.97	$ 18,794.71	$ 1,272,036.41	$ (19,888.97)	$ 1,252,147.44	$ 1,727.97	$ 10,117.13	$ 11,845.10
	Feb-25	$ 44,554.60	$ 1,335,385.72	$ 1,772.70	$ 20,567.41	$ 1,314,818.31	$ (21,500.56)	$ 1,293,317.75	$ 1,772.70	$ 10,449.78	$ 12,222.48
	Mar-25	$ 55,975.95	$ 1,391,361.67	$ 1,840.55	$ 22,407.96	$ 1,368,953.71	$ (23,151.24)	$ 1,345,802.47	$ 1,840.55	$ 10,873.85	$ 12,714.40
	Apr-25	$ 67,397.29	$ 1,458,758.96	$ 1,923.83	$ 24,331.79	$ 1,434,427.17	$ (24,856.28)	$ 1,409,570.89	$ 1,923.83	$ 11,389.09	$ 13,312.92
	May-25	$ 67,397.29	$ 1,526,156.25	$ 2,014.82	$ 26,346.61	$ 1,499,809.64	$ (26,623.21)	$ 1,473,186.43	$ 2,014.82	$ 11,903.09	$ 13,917.91
	Jun-25	$ 90,239.99	$ 1,616,396.24	$ 2,121.22	$ 28,467.83	$ 1,587,928.41	$ (28,493.89)	$ 1,559,434.52	$ 2,121.22	$ 12,599.96	$ 14,721.18
	Jul-25	$ 90,239.99	$ 1,706,636.23	$ 2,243.05	$ 30,710.88	$ 1,675,925.35	$ (30,486.25)	$ 1,645,439.10	$ 2,243.05	$ 13,294.86	$ 15,537.91
	Aug-25	$ 113,082.69	$ 1,819,718.92	$ 2,380.29	$ 33,091.17	$ 1,786,627.75	$ (32,674.22)	$ 1,753,953.53	$ 2,380.29	$ 14,171.64	$ 16,551.93
	Sep-25	$ 113,082.69	$ 1,932,801.61	$ 2,532.95	$ 35,624.12	$ 1,897,177.49	$ (35,111.91)	$ 1,862,065.58	$ 2,532.95	$ 15,045.16	$ 17,578.11
	Oct-25	$ 90,239.99	$ 2,023,041.60	$ 2,670.19	$ 38,294.31	$ 1,984,747.29	$ (37,822.23)	$ 1,946,925.06	$ 2,670.19	$ 15,730.81	$ 18,401.00
	Nov-25	$ 67,397.30	$ 2,090,438.90	$ 2,776.60	$ 41,070.91	$ 2,049,367.99	$ (40,851.01)	$ 2,008,516.98	$ 2,776.60	$ 16,228.46	$ 19,005.06
	Dec-25	$ 33,133.26	$ 2,123,572.16	$ 2,844.46	$ 43,915.37	$ 2,079,656.79	$ (44,203.02)	$ 2,035,453.77	$ 2,844.46	$ 16,446.11	$ 19,290.57
2026	Jan-26	$ 25,074.25	$ 2,148,646.41	$ 2,883.75	$ 46,799.12	$ 2,101,847.29	$ (46,731.51)	$ 2,055,115.78	$ 2,883.75	$ 16,604.98	$ 19,488.73
	Feb-26	$ 49,598.11	$ 2,198,244.52	$ 2,934.15	$ 49,733.27	$ 2,148,511.25	$ (49,292.65)	$ 2,099,218.60	$ 2,934.15	$ 16,961.32	$ 19,895.47
	Mar-26	$ 61,860.05	$ 2,260,104.57	$ 3,009.39	$ 52,742.66	$ 2,207,361.91	$ (51,896.93)	$ 2,155,464.98	$ 3,009.39	$ 17,415.78	$ 20,425.17
	Apr-26	$ 74,121.98	$ 2,334,226.55	$ 3,101.17	$ 55,843.83	$ 2,278,382.72	$ (54,560.93)	$ 2,223,821.79	$ 3,101.17	$ 17,968.09	$ 21,069.26
	May-26	$ 74,121.97	$ 2,408,348.52	$ 3,201.24	$ 59,045.07	$ 2,349,303.45	$ (57,293.01)	$ 2,292,010.44	$ 3,201.24	$ 18,519.04	$ 21,720.28
	Jun-26	$ 98,645.84	$ 2,506,994.36	$ 3,317.86	$ 62,362.93	$ 2,444,631.43	$ (60,138.42)	$ 2,384,493.01	$ 3,317.86	$ 19,266.29	$ 22,584.15
	Jul-26	$ 98,645.84	$ 2,605,640.20	$ 3,451.03	$ 65,813.96	$ 2,539,826.24	$ (63,116.84)	$ 2,476,709.40	$ 3,451.03	$ 20,011.38	$ 23,462.41
	Aug-26	$ 123,169.71	$ 2,728,809.91	$ 3,600.75	$ 69,414.71	$ 2,659,395.20	$ (66,308.26)	$ 2,593,086.94	$ 3,600.75	$ 20,951.69	$ 24,552.44
	Sep-26	$ 123,169.71	$ 2,851,979.62	$ 3,767.03	$ 73,181.74	$ 2,778,797.88	$ (69,771.67)	$ 2,709,026.21	$ 3,767.03	$ 21,888.46	$ 25,655.49
	Oct-26	$ 98,645.85	$ 2,950,625.47	$ 3,916.76	$ 77,098.50	$ 2,873,526.97	$ (73,533.19)	$ 2,799,993.78	$ 3,916.76	$ 22,623.46	$ 26,540.22
	Nov-26	$ 74,121.98	$ 3,024,747.45	$ 4,033.38	$ 81,131.88	$ 2,943,615.57	$ (77,645.05)	$ 2,865,970.52	$ 4,033.38	$ 23,156.54	$ 27,189.92
	Dec-26	$ 37,336.18	$ 3,062,083.63	$ 4,108.61	$ 85,240.49	$ 2,976,843.14	$ (82,121.49)	$ 2,894,721.65	$ 4,108.61	$ 23,388.84	$ 27,497.45
2027	Jan-27	$ 28,684.05	$ 3,090,767.68	$ 4,153.17	$ 89,393.66	$ 3,001,374.02	$ (85,609.80)	$ 2,915,764.22	$ 4,153.17	$ 23,558.86	$ 27,712.03
	Feb-27	$ 55,012.81	$ 3,145,780.49	$ 4,209.67	$ 93,603.33	$ 3,052,177.16	$ (89,134.16)	$ 2,963,043.00	$ 4,209.67	$ 23,940.87	$ 28,150.54
	Mar-27	$ 68,177.20	$ 3,213,957.69	$ 4,292.82	$ 97,896.15	$ 3,116,061.54	$ (92,705.99)	$ 3,023,355.55	$ 4,292.82	$ 24,428.18	$ 28,721.00
	Apr-27	$ 81,341.58	$ 3,295,299.27	$ 4,393.75	$ 102,289.90	$ 3,193,009.37	$ (96,343.31)	$ 3,096,666.06	$ 4,393.75	$ 25,020.52	$ 29,414.27
	May-27	$ 81,341.58	$ 3,376,640.85	$ 4,503.56	$ 106,793.46	$ 3,269,847.39	$ (100,055.34)	$ 3,169,792.05	$ 4,503.56	$ 25,611.36	$ 30,114.92
	Jun-27	$ 107,670.34	$ 3,484,311.19	$ 4,631.14	$ 111,424.60	$ 3,372,886.59	$ (103,890.99)	$ 3,268,995.60	$ 4,631.14	$ 26,412.91	$ 31,044.05
	Jul-27	$ 107,670.35	$ 3,591,981.54	$ 4,776.50	$ 116,201.10	$ 3,475,780.44	$ (107,871.81)	$ 3,367,908.63	$ 4,776.50	$ 27,212.11	$ 31,988.61
	Aug-27	$ 133,999.11	$ 3,725,980.65	$ 4,939.62	$ 121,140.72	$ 3,604,839.93	$ (112,084.29)	$ 3,492,755.64	$ 4,939.62	$ 28,220.85	$ 33,160.47
	Sep-27	$ 133,999.11	$ 3,859,979.76	$ 5,120.52	$ 126,261.24	$ 3,733,718.52	$ (116,592.68)	$ 3,617,125.84	$ 5,120.52	$ 29,225.74	$ 34,346.26
	Oct-27	$ 107,670.35	$ 3,967,650.11	$ 5,283.65	$ 131,544.89	$ 3,836,105.22	$ (121,426.53)	$ 3,714,678.69	$ 5,283.65	$ 30,013.95	$ 35,297.60
	Nov-27	$ 81,341.58	$ 4,048,991.69	$ 5,411.23	$ 136,956.12	$ 3,912,035.57	$ (126,644.96)	$ 3,785,390.61	$ 5,411.23	$ 30,585.29	$ 35,996.52
	Dec-27	$ 41,848.43	$ 4,090,840.12	$ 5,494.39	$ 142,450.51	$ 3,948,389.61	$ (132,272.34)	$ 3,816,117.27	$ 5,494.39	$ 30,833.56	$ 36,327.95

2023 Total =	$ 498,724.77	2023 Annual Revenue Requirement =	$ 25,726.34
2024 Total =	$ 770,394.44	2024 Annual Revenue Requirement =	$ 97,128.36
2025 Total =	$ 854,452.95	2025 Annual Revenue Requirement =	$ 185,098.57
2026 Total =	$ 938,511.47	2026 Annual Revenue Requirement =	$ 280,080.99
2027 Total =	$ 1,028,756.49	2027 Annual Revenue Requirement =	$ 382,274.22

[1]per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
Underground Cable Revenue Requirement Calculation
U/G Conduct, Dvcs

Reg Depreciation	2.69%	FERC Account 367 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	3.23%	FERC Account 367 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	*[b]*	*[c]*	*[d]*	*[e]*	*[f]*	*[g]=[d]-[f]*	*[n]*	*[o]=[g]+[n]*	*[p]=[e]*	*[q]*	*[r]=[p]+[q]*
2023	Jan-23	$ 112,022.37	$ 112,022.37	$ 125.56	$ 125.56	$ 111,896.81	$ (61.78)	$ 111,835.03	$ 125.56	$ 846.79	$ 972.35
	Feb-23	$ 347,483.30	$ 459,505.67	$ 640.59	$ 766.15	$ 458,739.52	$ (307.81)	$ 458,431.71	$ 640.59	$ 3,471.16	$ 4,111.75
	Mar-23	$ 465,213.78	$ 924,719.45	$ 1,551.49	$ 2,317.64	$ 922,401.81	$ (783.24)	$ 921,618.57	$ 1,551.49	$ 6,978.33	$ 8,529.82
	Apr-23	$ 582,944.23	$ 1,507,663.68	$ 2,726.30	$ 5,043.94	$ 1,502,619.74	$ (1,603.77)	$ 1,501,015.97	$ 2,726.30	$ 11,365.42	$ 14,091.72
	May-23	$ 582,944.23	$ 2,090,607.91	$ 4,033.06	$ 9,077.00	$ 2,081,530.91	$ (2,816.64)	$ 2,078,714.27	$ 4,033.06	$ 15,739.65	$ 19,772.71
	Jun-23	$ 818,405.17	$ 2,909,013.08	$ 5,603.74	$ 14,680.74	$ 2,894,332.34	$ (4,803.75)	$ 2,889,528.59	$ 5,603.74	$ 21,878.98	$ 27,482.72
	Jul-23	$ 818,405.17	$ 3,727,418.25	$ 7,438.33	$ 22,119.07	$ 3,705,299.18	$ (7,693.56)	$ 3,697,605.62	$ 7,438.33	$ 27,997.60	$ 35,435.93
	Aug-23	$ 1,053,866.12	$ 4,781,284.37	$ 9,536.84	$ 31,655.91	$ 4,749,628.46	$ (12,180.89)	$ 4,737,447.57	$ 9,536.84	$ 35,871.09	$ 45,407.93
	Sep-23	$ 1,053,866.12	$ 5,835,150.49	$ 11,899.25	$ 43,555.16	$ 5,791,595.33	$ (18,736.87)	$ 5,772,858.46	$ 11,899.25	$ 43,711.03	$ 55,610.28
	Oct-23	$ 818,405.17	$ 6,653,555.66	$ 13,997.76	$ 57,552.92	$ 6,596,002.74	$ (27,530.45)	$ 6,568,472.29	$ 13,997.76	$ 49,735.27	$ 63,733.03
	Nov-23	$ 582,944.23	$ 7,236,499.89	$ 18,693.70	$ 76,246.62	$ 7,160,253.27	$ (38,039.55)	$ 7,122,213.72	$ 18,693.70	$ 57,546.24	$ 76,239.94
	Dec-23	$ 229,752.83	$ 7,466,252.72	$ 19,787.45	$ 96,034.07	$ 7,370,218.65	$ (50,618.51)	$ 7,319,600.14	$ 19,787.45	$ 59,141.09	$ 78,928.54
2024	Jan-24	$ 274,705.65	$ 7,740,958.37	$ 20,466.37	$ 116,500.44	$ 7,624,457.93	$ (57,582.59)	$ 7,566,875.34	$ 20,466.37	$ 61,139.03	$ 81,605.40
	Feb-24	$ 591,508.23	$ 8,332,466.60	$ 21,632.15	$ 138,132.59	$ 8,194,334.01	$ (64,780.77)	$ 8,129,553.24	$ 21,632.15	$ 65,685.36	$ 87,317.51
	Mar-24	$ 749,909.53	$ 9,082,376.13	$ 23,437.48	$ 161,570.07	$ 8,920,806.06	$ (72,256.00)	$ 8,848,550.06	$ 23,437.48	$ 71,494.73	$ 94,932.21
	Apr-24	$ 908,310.79	$ 9,990,686.92	$ 25,669.16	$ 187,239.23	$ 9,803,447.69	$ (80,158.57)	$ 9,723,289.12	$ 25,669.16	$ 78,562.47	$ 104,231.63
	May-24	$ 908,310.80	$ 10,898,997.72	$ 28,114.03	$ 215,353.26	$ 10,683,644.46	$ (88,559.98)	$ 10,595,084.48	$ 28,114.03	$ 85,606.42	$ 113,720.45
	Jun-24	$ 1,225,113.38	$ 12,124,111.10	$ 30,985.27	$ 246,338.53	$ 11,877,772.57	$ (97,977.31)	$ 11,779,795.26	$ 30,985.27	$ 95,178.68	$ 126,163.95
	Jul-24	$ 1,225,113.38	$ 13,349,224.48	$ 34,282.86	$ 280,621.39	$ 13,068,603.09	$ (108,594.22)	$ 12,960,008.87	$ 34,282.86	$ 104,714.60	$ 138,997.46
	Aug-24	$ 1,541,915.97	$ 14,891,140.45	$ 38,006.82	$ 318,628.21	$ 14,572,512.24	$ (121,368.62)	$ 14,451,143.62	$ 38,006.82	$ 116,762.71	$ 154,769.53
	Sep-24	$ 1,541,915.97	$ 16,433,056.42	$ 42,157.15	$ 360,785.36	$ 16,072,271.06	$ (136,978.73)	$ 15,935,292.33	$ 42,157.15	$ 128,754.37	$ 170,911.52
	Oct-24	$ 1,225,113.38	$ 17,658,169.80	$ 45,881.11	$ 406,666.47	$ 17,251,503.33	$ (155,778.11)	$ 17,095,725.22	$ 45,881.11	$ 138,130.46	$ 184,011.57
	Nov-24	$ 908,310.79	$ 18,566,480.59	$ 48,752.34	$ 455,418.81	$ 18,111,061.78	$ (178,473.86)	$ 17,932,587.92	$ 48,752.34	$ 144,892.17	$ 193,644.51
	Dec-24	$ 433,106.94	$ 18,999,587.53	$ 50,557.67	$ 505,976.48	$ 18,493,611.05	$ (205,142.08)	$ 18,288,468.97	$ 50,557.67	$ 147,767.62	$ 198,325.29
2025	Jan-25	$ 325,042.19	$ 19,324,629.72	$ 51,578.01	$ 557,554.49	$ 18,767,075.23	$ (221,752.70)	$ 18,545,322.53	$ 51,578.01	$ 149,842.95	$ 201,420.96
	Feb-25	$ 667,013.05	$ 19,991,642.77	$ 52,913.15	$ 610,467.64	$ 19,381,175.13	$ (238,621.65)	$ 19,142,553.48	$ 52,913.15	$ 154,668.48	$ 207,581.63
	Mar-25	$ 837,998.48	$ 20,829,641.25	$ 54,938.64	$ 665,406.28	$ 20,164,234.97	$ (255,797.97)	$ 19,908,437.00	$ 54,938.64	$ 160,856.68	$ 215,795.32
	Apr-25	$ 1,008,983.89	$ 21,838,625.14	$ 57,424.38	$ 722,830.66	$ 21,115,794.48	$ (273,447.14)	$ 20,842,347.34	$ 57,424.38	$ 168,402.51	$ 225,826.89
	May-25	$ 1,008,983.89	$ 22,847,609.03	$ 60,140.22	$ 782,970.88	$ 22,064,638.15	$ (291,650.45)	$ 21,772,987.70	$ 60,140.22	$ 175,921.92	$ 236,062.14
	Jun-25	$ 1,350,954.75	$ 24,198,563.78	$ 63,316.31	$ 846,287.19	$ 23,352,276.59	$ (310,971.29)	$ 23,041,305.30	$ 63,316.31	$ 186,169.71	$ 249,486.02
	Jul-25	$ 1,350,954.75	$ 25,549,518.53	$ 66,952.63	$ 913,239.82	$ 24,636,278.71	$ (331,614.94)	$ 24,304,663.77	$ 66,952.63	$ 196,377.42	$ 263,330.05
	Aug-25	$ 1,692,925.61	$ 27,242,444.14	$ 71,049.18	$ 984,289.00	$ 26,258,155.14	$ (354,625.20)	$ 25,903,529.94	$ 71,049.18	$ 209,295.98	$ 280,345.16
	Sep-25	$ 1,692,925.61	$ 28,935,369.75	$ 75,605.97	$ 1,059,894.97	$ 27,875,474.78	$ (380,748.89)	$ 27,494,725.89	$ 75,605.97	$ 222,152.56	$ 297,758.53
	Oct-25	$ 1,350,954.74	$ 30,286,324.49	$ 79,702.53	$ 1,139,597.50	$ 29,146,726.99	$ (410,392.17)	$ 28,736,334.82	$ 79,702.53	$ 232,184.55	$ 311,887.08
	Nov-25	$ 1,008,983.88	$ 31,295,308.37	$ 82,878.61	$ 1,222,476.11	$ 30,072,832.26	$ (444,367.36)	$ 29,628,464.90	$ 82,878.61	$ 239,392.80	$ 322,271.41
	Dec-25	$ 496,027.62	$ 31,791,335.99	$ 84,904.11	$ 1,307,380.22	$ 30,483,955.77	$ (482,903.73)	$ 30,001,052.04	$ 84,904.11	$ 242,403.24	$ 327,307.35
2026	Jan-26	$ 375,378.74	$ 32,166,714.73	$ 86,076.88	$ 1,393,457.10	$ 30,773,257.63	$ (508,950.46)	$ 30,264,307.17	$ 86,076.88	$ 244,530.29	$ 330,607.17
	Feb-26	$ 742,517.87	$ 32,909,232.60	$ 87,581.38	$ 1,481,038.48	$ 31,428,194.12	$ (535,279.74)	$ 30,892,914.38	$ 87,581.38	$ 249,609.33	$ 337,190.71
	Mar-26	$ 926,087.44	$ 33,835,320.04	$ 89,827.04	$ 1,570,865.52	$ 32,264,454.52	$ (561,946.71)	$ 31,702,507.81	$ 89,827.04	$ 256,150.70	$ 345,977.74
	Apr-26	$ 1,109,656.98	$ 34,944,977.02	$ 92,566.82	$ 1,663,432.34	$ 33,281,544.68	$ (589,132.05)	$ 32,692,412.63	$ 92,566.82	$ 264,148.96	$ 356,715.78
	May-26	$ 1,109,656.98	$ 36,054,634.00	$ 95,553.64	$ 1,758,985.98	$ 34,295,648.02	$ (616,926.82)	$ 33,678,721.20	$ 95,553.64	$ 272,118.16	$ 367,671.80
	Jun-26	$ 1,476,796.11	$ 37,531,430.11	$ 99,034.58	$ 1,858,020.56	$ 35,673,409.55	$ (645,940.75)	$ 35,027,468.80	$ 99,034.58	$ 283,015.81	$ 382,050.39
	Jul-26	$ 1,476,796.11	$ 39,008,226.22	$ 103,009.62	$ 1,961,030.18	$ 37,047,196.04	$ (676,400.70)	$ 36,370,795.34	$ 103,009.62	$ 293,869.65	$ 396,879.27
	Aug-26	$ 1,843,935.25	$ 40,852,161.47	$ 107,478.77	$ 2,068,508.95	$ 38,783,652.52	$ (709,436.39)	$ 38,074,216.13	$ 107,478.77	$ 307,632.99	$ 415,111.76
	Sep-26	$ 1,843,935.25	$ 42,696,096.72	$ 112,442.03	$ 2,180,950.98	$ 40,515,145.74	$ (745,863.24)	$ 39,769,282.50	$ 112,442.03	$ 321,328.83	$ 433,770.86
	Oct-26	$ 1,476,796.11	$ 44,172,892.83	$ 116,911.18	$ 2,297,862.16	$ 41,875,030.67	$ (786,140.00)	$ 41,088,890.67	$ 116,911.18	$ 331,991.03	$ 448,902.21
	Nov-26	$ 1,109,656.97	$ 45,282,549.80	$ 120,392.12	$ 2,418,254.28	$ 42,864,295.52	$ (831,184.21)	$ 42,033,111.31	$ 120,392.12	$ 339,620.17	$ 460,012.29
	Dec-26	$ 558,948.30	$ 45,841,498.10	$ 122,637.78	$ 2,540,892.06	$ 43,300,606.04	$ (881,378.29)	$ 42,419,227.75	$ 122,637.78	$ 342,739.92	$ 465,377.70
2027	Jan-27	$ 429,419.94	$ 46,270,918.04	$ 123,967.96	$ 2,664,860.02	$ 43,606,058.02	$ (916,596.91)	$ 42,689,461.11	$ 123,967.96	$ 344,923.36	$ 468,891.32
	Feb-27	$ 823,579.67	$ 47,094,497.71	$ 125,654.29	$ 2,790,514.31	$ 44,303,983.40	$ (952,124.09)	$ 43,351,859.31	$ 125,654.29	$ 350,275.42	$ 475,929.71
	Mar-27	$ 1,020,659.54	$ 48,115,157.25	$ 128,136.33	$ 2,918,650.64	$ 45,196,506.61	$ (988,021.50)	$ 44,208,485.11	$ 128,136.33	$ 357,196.81	$ 485,333.14
	Apr-27	$ 1,217,739.38	$ 49,332,896.63	$ 131,148.84	$ 3,049,799.48	$ 46,283,097.15	$ (1,024,486.15)	$ 45,258,611.00	$ 131,148.84	$ 365,681.64	$ 496,830.48
	May-27	$ 1,217,739.38	$ 50,550,636.01	$ 134,426.59	$ 3,184,226.07	$ 47,366,409.94	$ (1,061,619.59)	$ 46,304,790.35	$ 134,426.59	$ 374,134.59	$ 508,561.18
	Jun-27	$ 1,611,899.11	$ 52,162,535.12	$ 138,234.81	$ 3,322,460.88	$ 48,840,074.24	$ (1,100,081.28)	$ 47,739,992.96	$ 138,234.81	$ 385,730.77	$ 523,965.58
	Jul-27	$ 1,611,899.11	$ 53,774,434.23	$ 142,573.50	$ 3,465,034.38	$ 50,309,399.85	$ (1,140,121.29)	$ 49,169,278.56	$ 142,573.50	$ 397,279.15	$ 539,852.65
	Aug-27	$ 2,006,058.85	$ 55,780,493.08	$ 147,442.67	$ 3,612,477.05	$ 52,168,016.03	$ (1,182,961.55)	$ 50,985,054.48	$ 147,442.67	$ 411,950.30	$ 559,392.97
	Sep-27	$ 2,006,058.85	$ 57,786,551.93	$ 152,842.31	$ 3,765,319.36	$ 54,021,232.57	$ (1,229,491.13)	$ 52,791,741.44	$ 152,842.31	$ 426,548.01	$ 579,390.32
	Oct-27	$ 1,611,899.11	$ 59,398,451.04	$ 157,711.48	$ 3,923,030.84	$ 55,475,420.20	$ (1,280,225.27)	$ 54,195,194.93	$ 157,711.48	$ 437,887.67	$ 595,599.15
	Nov-27	$ 1,217,739.37	$ 60,616,190.41	$ 161,519.70	$ 4,084,550.54	$ 56,531,639.87	$ (1,336,194.44)	$ 55,195,445.43	$ 161,519.70	$ 445,969.52	$ 607,489.22
	Dec-27	$ 626,499.80	$ 61,242,690.21	$ 164,001.74	$ 4,248,552.28	$ 56,994,137.93	$ (1,397,945.51)	$ 55,596,192.42	$ 164,001.74	$ 449,207.49	$ 613,209.23

2023 Total =	$ 7,466,252.72	2023 Annual Revenue Requirement =	$ 430,316.72
2024 Total =	$ 11,533,334.81	2024 Annual Revenue Requirement =	$ 1,648,631.03
2025 Total =	$ 12,791,748.46	2025 Annual Revenue Requirement =	$ 3,139,072.54
2026 Total =	$ 14,050,162.11	2026 Annual Revenue Requirement =	$ 4,740,267.68
2027 Total =	$ 15,401,192.11	2027 Annual Revenue Requirement =	$ 6,454,444.95

[1] per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
Underground Cable Revenue Requirement Calculation
Line Transformers

Reg Depreciation	1.82%	FERC Account 368 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	1.83%	FERC Account 368 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	*[b]*	*[c]*	*[d]*	*[e]*	*[f]*	*[g]=[d]-[f]*	*[n]*	*[o]=[g]+[n]*	*[p]=[e]*	*[q]*	*[r]=[p]+[q]*
2023	Jan-23	$ 13,724.71	$ 13,724.71	$ 10.41	$ 10.41	$ 13,714.30	$ (8.94)	$ 13,705.36	$ 10.41	$ 103.77	$ 114.18
	Feb-23	$ 42,572.83	$ 56,297.54	$ 53.10	$ 63.51	$ 56,234.03	$ (46.07)	$ 56,187.96	$ 53.10	$ 425.44	$ 478.54
	Mar-23	$ 56,996.88	$ 113,294.42	$ 128.61	$ 192.12	$ 113,102.30	$ (121.23)	$ 112,981.07	$ 128.61	$ 855.47	$ 984.08
	Apr-23	$ 71,420.94	$ 184,715.36	$ 225.99	$ 418.11	$ 184,297.25	$ (251.49)	$ 184,045.76	$ 225.99	$ 1,393.56	$ 1,619.55
	May-23	$ 71,420.94	$ 256,136.30	$ 334.31	$ 752.42	$ 255,383.88	$ (444.07)	$ 254,939.81	$ 334.31	$ 1,930.36	$ 2,264.67
	Jun-23	$ 100,269.06	$ 356,405.36	$ 464.51	$ 1,216.93	$ 355,188.43	$ (748.63)	$ 354,439.80	$ 464.51	$ 2,683.75	$ 3,148.26
	Jul-23	$ 100,269.06	$ 456,674.42	$ 616.59	$ 1,833.52	$ 454,840.90	$ (1,183.79)	$ 453,657.11	$ 616.59	$ 3,435.01	$ 4,051.60
	Aug-23	$ 129,117.16	$ 585,791.58	$ 790.54	$ 2,624.06	$ 583,167.52	$ (1,837.56)	$ 581,329.96	$ 790.54	$ 4,401.72	$ 5,192.26
	Sep-23	$ 129,117.16	$ 714,908.74	$ 986.36	$ 3,610.42	$ 711,298.32	$ (2,770.53)	$ 708,527.79	$ 986.36	$ 5,364.84	$ 6,351.20
	Oct-23	$ 100,269.06	$ 815,177.80	$ 1,160.32	$ 4,770.74	$ 810,407.06	$ (4,000.53)	$ 806,406.53	$ 1,160.32	$ 6,105.96	$ 7,266.28
	Nov-23	$ 71,420.94	$ 886,598.74	$ 1,297.60	$ 6,068.34	$ 880,530.40	$ (5,561.25)	$ 874,969.15	$ 1,297.60	$ 7,069.60	$ 8,367.20
	Dec-23	$ 28,148.77	$ 914,747.51	$ 1,373.53	$ 7,441.87	$ 907,305.64	$ (7,391.54)	$ 899,914.10	$ 1,373.53	$ 7,271.15	$ 8,644.68
2024	Jan-24	$ 33,656.28	$ 948,403.79	$ 1,420.65	$ 8,862.52	$ 939,541.27	$ (8,543.84)	$ 930,997.43	$ 1,420.65	$ 7,522.30	$ 8,942.95
	Feb-24	$ 72,470.18	$ 1,020,873.97	$ 1,501.57	$ 10,364.09	$ 1,010,509.88	$ (9,741.85)	$ 1,000,768.03	$ 1,501.57	$ 8,086.03	$ 9,587.60
	Mar-24	$ 91,877.13	$ 1,112,751.10	$ 1,626.89	$ 11,990.98	$ 1,100,760.12	$ (11,000.19)	$ 1,089,759.93	$ 1,626.89	$ 8,805.07	$ 10,431.96
	Apr-24	$ 111,284.09	$ 1,224,035.19	$ 1,781.80	$ 13,772.78	$ 1,210,262.41	$ (12,343.49)	$ 1,197,918.92	$ 1,781.80	$ 9,678.97	$ 11,460.77
	May-24	$ 111,284.08	$ 1,335,319.27	$ 1,951.51	$ 15,724.29	$ 1,319,594.98	$ (13,783.63)	$ 1,305,811.35	$ 1,951.51	$ 10,550.73	$ 12,502.24
	Jun-24	$ 150,097.98	$ 1,485,417.25	$ 2,150.81	$ 17,875.10	$ 1,467,542.15	$ (15,390.20)	$ 1,452,151.95	$ 2,150.81	$ 11,733.13	$ 13,883.94
	Jul-24	$ 150,097.98	$ 1,635,515.23	$ 2,379.71	$ 20,254.81	$ 1,615,260.42	$ (17,191.93)	$ 1,598,068.49	$ 2,379.71	$ 12,912.11	$ 15,291.82
	Aug-24	$ 188,911.87	$ 1,824,427.10	$ 2,638.21	$ 22,893.02	$ 1,801,534.08	$ (19,312.40)	$ 1,782,221.68	$ 2,638.21	$ 14,400.04	$ 17,038.25
	Sep-24	$ 188,911.87	$ 2,013,338.97	$ 2,926.30	$ 25,819.32	$ 1,987,519.65	$ (21,840.95)	$ 1,965,678.70	$ 2,926.30	$ 15,882.34	$ 18,808.64
	Oct-24	$ 150,097.98	$ 2,163,436.95	$ 3,184.79	$ 29,004.11	$ 2,134,432.84	$ (24,814.66)	$ 2,109,618.18	$ 3,184.79	$ 17,045.34	$ 20,230.13
	Nov-24	$ 111,284.08	$ 2,274,721.03	$ 3,384.10	$ 32,388.21	$ 2,242,332.82	$ (28,307.70)	$ 2,214,025.12	$ 3,384.10	$ 17,888.93	$ 21,273.03
	Dec-24	$ 53,063.23	$ 2,327,784.26	$ 3,509.41	$ 35,897.62	$ 2,291,886.64	$ (32,313.82)	$ 2,259,572.82	$ 3,509.41	$ 18,256.95	$ 21,766.36
2025	Jan-25	$ 39,823.40	$ 2,367,607.66	$ 3,580.24	$ 39,477.86	$ 2,328,129.80	$ (35,102.61)	$ 2,293,027.19	$ 3,580.24	$ 18,527.26	$ 22,107.50
	Feb-25	$ 81,720.85	$ 2,449,328.51	$ 3,672.91	$ 43,150.77	$ 2,406,177.74	$ (37,942.56)	$ 2,368,235.18	$ 3,672.91	$ 19,134.92	$ 22,807.83
	Mar-25	$ 102,669.58	$ 2,551,998.09	$ 3,813.51	$ 46,964.28	$ 2,505,033.81	$ (40,849.77)	$ 2,464,184.04	$ 3,813.51	$ 19,910.17	$ 23,723.68
	Apr-25	$ 123,618.31	$ 2,675,616.40	$ 3,986.06	$ 50,950.34	$ 2,624,666.06	$ (43,851.23)	$ 2,580,814.83	$ 3,986.06	$ 20,852.53	$ 24,838.59
	May-25	$ 123,618.31	$ 2,799,234.71	$ 4,174.57	$ 55,124.91	$ 2,744,109.80	$ (46,960.27)	$ 2,697,149.53	$ 4,174.57	$ 21,792.50	$ 25,967.07
	Jun-25	$ 165,515.76	$ 2,964,750.47	$ 4,395.04	$ 59,519.95	$ 2,905,230.52	$ (50,252.64)	$ 2,854,977.88	$ 4,395.04	$ 23,067.72	$ 27,462.76
	Jul-25	$ 165,515.76	$ 3,130,266.23	$ 4,647.45	$ 64,167.40	$ 3,066,098.83	$ (53,760.21)	$ 3,012,338.62	$ 4,647.45	$ 24,339.17	$ 28,986.62
	Aug-25	$ 207,413.21	$ 3,337,679.44	$ 4,931.81	$ 69,099.21	$ 3,268,580.23	$ (57,617.60)	$ 3,210,962.63	$ 4,931.81	$ 25,944.01	$ 30,875.82
	Sep-25	$ 207,413.21	$ 3,545,092.65	$ 5,248.11	$ 74,347.32	$ 3,470,745.33	$ (61,923.03)	$ 3,408,822.30	$ 5,248.11	$ 27,542.69	$ 32,790.80
	Oct-25	$ 165,515.77	$ 3,710,608.42	$ 5,532.47	$ 79,879.79	$ 3,630,728.63	$ (66,719.53)	$ 3,564,009.10	$ 5,532.47	$ 28,796.57	$ 34,329.04
	Nov-25	$ 123,618.31	$ 3,834,226.73	$ 5,752.94	$ 85,632.73	$ 3,748,594.00	$ (72,093.17)	$ 3,676,500.83	$ 5,752.94	$ 29,705.48	$ 35,458.42
	Dec-25	$ 60,772.12	$ 3,894,998.85	$ 5,893.53	$ 91,526.26	$ 3,803,472.59	$ (78,055.24)	$ 3,725,417.35	$ 5,893.53	$ 30,100.72	$ 35,994.25
2026	Jan-26	$ 45,990.51	$ 3,940,989.36	$ 5,974.94	$ 97,501.20	$ 3,843,488.16	$ (82,504.24)	$ 3,760,983.92	$ 5,974.94	$ 30,388.09	$ 36,363.03
	Feb-26	$ 90,971.52	$ 4,031,960.88	$ 6,079.37	$ 103,580.57	$ 3,928,380.31	$ (87,009.85)	$ 3,841,370.46	$ 6,079.37	$ 31,037.60	$ 37,116.97
	Mar-26	$ 113,462.03	$ 4,145,422.91	$ 6,235.26	$ 109,815.83	$ 4,035,607.08	$ (91,589.64)	$ 3,944,017.44	$ 6,235.26	$ 31,866.97	$ 38,102.23
	Apr-26	$ 135,952.52	$ 4,281,375.43	$ 6,425.43	$ 116,241.26	$ 4,165,134.17	$ (96,272.98)	$ 4,068,861.19	$ 6,425.43	$ 32,875.68	$ 39,301.11
	May-26	$ 135,952.53	$ 4,417,327.96	$ 6,632.76	$ 122,874.02	$ 4,294,453.94	$ (101,074.63)	$ 4,193,379.31	$ 6,632.76	$ 33,881.77	$ 40,514.53
	Jun-26	$ 180,933.55	$ 4,598,261.51	$ 6,874.39	$ 129,748.41	$ 4,468,513.10	$ (106,076.52)	$ 4,362,436.58	$ 6,874.39	$ 35,247.72	$ 42,122.11
	Jul-26	$ 180,933.55	$ 4,779,195.06	$ 7,150.31	$ 136,898.72	$ 4,642,296.34	$ (111,313.66)	$ 4,530,982.68	$ 7,150.31	$ 36,609.55	$ 43,759.86
	Aug-26	$ 225,914.56	$ 5,005,109.62	$ 7,460.53	$ 144,359.25	$ 4,860,750.37	$ (116,931.68)	$ 4,743,818.69	$ 7,460.53	$ 38,329.22	$ 45,789.75
	Sep-26	$ 225,914.56	$ 5,231,024.18	$ 7,805.05	$ 152,164.30	$ 5,078,859.88	$ (123,037.70)	$ 4,955,822.18	$ 7,805.05	$ 40,042.17	$ 47,847.22
	Oct-26	$ 180,933.54	$ 5,411,957.72	$ 8,115.27	$ 160,279.57	$ 5,251,678.15	$ (129,680.71)	$ 5,121,997.44	$ 8,115.27	$ 41,384.84	$ 49,500.11
	Nov-26	$ 135,952.53	$ 5,547,910.25	$ 8,356.90	$ 168,636.47	$ 5,379,273.78	$ (136,958.68)	$ 5,242,315.10	$ 8,356.90	$ 42,356.99	$ 50,713.89
	Dec-26	$ 68,481.02	$ 5,616,391.27	$ 8,512.78	$ 177,149.25	$ 5,439,242.02	$ (144,900.42)	$ 5,294,341.60	$ 8,512.78	$ 42,777.35	$ 51,290.13
2027	Jan-27	$ 52,611.51	$ 5,669,002.78	$ 8,605.11	$ 185,754.36	$ 5,483,248.42	$ (151,026.84)	$ 5,332,221.58	$ 8,605.11	$ 43,083.42	$ 51,688.53
	Feb-27	$ 100,903.02	$ 5,769,905.80	$ 8,722.17	$ 194,476.53	$ 5,575,429.27	$ (157,215.70)	$ 5,418,213.57	$ 8,722.17	$ 43,778.22	$ 52,500.39
	Mar-27	$ 125,048.78	$ 5,894,954.58	$ 8,894.46	$ 203,370.99	$ 5,691,583.59	$ (163,486.19)	$ 5,528,097.40	$ 8,894.46	$ 44,666.06	$ 53,560.52
	Apr-27	$ 149,194.52	$ 6,044,149.10	$ 9,103.57	$ 212,474.56	$ 5,831,674.54	$ (169,870.20)	$ 5,661,804.34	$ 9,103.57	$ 45,746.39	$ 54,849.96
	May-27	$ 149,194.52	$ 6,193,343.62	$ 9,331.09	$ 221,805.65	$ 5,971,537.97	$ (176,384.05)	$ 5,795,153.92	$ 9,331.09	$ 46,823.83	$ 56,154.92
	Jun-27	$ 197,486.05	$ 6,390,829.67	$ 9,595.43	$ 231,401.08	$ 6,159,428.59	$ (183,116.28)	$ 5,976,312.31	$ 9,595.43	$ 48,287.56	$ 57,882.99
	Jul-27	$ 197,486.04	$ 6,588,315.71	$ 9,896.60	$ 241,297.68	$ 6,347,018.03	$ (190,105.28)	$ 6,156,912.75	$ 9,896.60	$ 49,746.78	$ 59,643.38
	Aug-27	$ 245,777.56	$ 6,834,093.27	$ 10,234.59	$ 251,532.27	$ 6,582,561.00	$ (197,508.51)	$ 6,385,052.49	$ 10,234.59	$ 51,590.10	$ 61,824.69
	Sep-27	$ 245,777.56	$ 7,079,870.83	$ 10,609.40	$ 262,141.67	$ 6,817,729.16	$ (205,442.65)	$ 6,612,286.51	$ 10,609.40	$ 53,426.12	$ 64,035.52
	Oct-27	$ 197,486.04	$ 7,277,356.87	$ 10,947.39	$ 273,089.06	$ 7,004,267.81	$ (213,963.08)	$ 6,790,304.73	$ 10,947.39	$ 54,864.47	$ 65,811.86
	Nov-27	$ 149,194.53	$ 7,426,551.40	$ 11,211.73	$ 284,300.79	$ 7,142,250.61	$ (223,180.54)	$ 6,919,070.07	$ 11,211.73	$ 55,904.87	$ 67,116.60
	Dec-27	$ 76,757.27	$ 7,503,308.67	$ 11,384.02	$ 295,684.81	$ 7,207,623.86	$ (233,142.66)	$ 6,974,481.20	$ 11,384.02	$ 56,352.59	$ 67,736.61

2023 Total =	$ 914,747.51
2024 Total =	$ 1,413,036.75
2025 Total =	$ 1,567,214.59
2026 Total =	$ 1,721,392.42
2027 Total =	$ 1,886,917.40

2023 Annual Revenue Requirement =	$ 48,482.50
2024 Annual Revenue Requirement =	$ 181,217.69
2025 Annual Revenue Requirement =	$ 345,342.38
2026 Annual Revenue Requirement =	$ 522,420.94
2027 Annual Revenue Requirement =	$ 712,805.97

[1]per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
Recloser Revenue Requirement Calculation
Station Equipment

Reg Depreciation	1.08%	FERC Account 362 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	1.35%	FERC Account 362 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	*[b]*	*[c]*	*[d]*	*[e]*	*[f]*	*[g]=[d]-[f]*	*[n]*	*[o]=[g]+[n]*	*[p]=[e]*	*[q]*	*[r]=[p]+[q]*
2023	Jan-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feb-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mar-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Apr-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	May-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jun-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jul-23	$ 268,998.92	$ 268,998.92	$ 121.05	$ 121.05	$ 268,877.87	$ (429.33)	$ 268,448.54	$ 121.05	$ 2,032.64	$ 2,153.69
	Aug-23	$ 313,941.75	$ 582,940.67	$ 383.37	$ 504.42	$ 582,436.25	$ (1,434.39)	$ 581,001.86	$ 383.37	$ 4,399.24	$ 4,782.61
	Sep-23	$ 313,941.75	$ 896,882.42	$ 665.92	$ 1,170.34	$ 895,712.08	$ (3,171.59)	$ 892,540.49	$ 665.92	$ 6,758.15	$ 7,424.07
	Oct-23	$ 313,941.75	$ 1,210,824.17	$ 948.47	$ 2,118.81	$ 1,208,705.36	$ (5,910.90)	$ 1,202,794.46	$ 948.47	$ 9,107.34	$ 10,055.81
	Nov-23	$ 87,048.42	$ 1,297,872.59	$ 1,411.14	$ 3,529.95	$ 1,294,342.64	$ (8,972.03)	$ 1,285,370.61	$ 1,411.14	$ 10,385.57	$ 11,796.71
	Dec-23	$ 87,048.42	$ 1,384,921.01	$ 1,509.07	$ 5,039.02	$ 1,379,881.99	$ (12,904.47)	$ 1,366,977.52	$ 1,509.07	$ 11,044.94	$ 12,554.01
2024	Jan-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 6,597.06	$ 1,378,323.95	$ (14,768.34)	$ 1,363,555.61	$ 1,558.04	$ 11,017.29	$ 12,575.33
	Feb-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 8,155.10	$ 1,376,765.91	$ (16,632.21)	$ 1,360,133.70	$ 1,558.04	$ 10,989.64	$ 12,547.68
	Mar-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 9,713.14	$ 1,375,207.87	$ (18,496.08)	$ 1,356,711.79	$ 1,558.04	$ 10,961.99	$ 12,520.03
	Apr-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 11,271.18	$ 1,373,649.83	$ (20,359.95)	$ 1,353,289.88	$ 1,558.04	$ 10,934.34	$ 12,492.38
	May-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 12,829.22	$ 1,372,091.79	$ (22,223.82)	$ 1,349,867.97	$ 1,558.04	$ 10,906.70	$ 12,464.74
	Jun-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 14,387.26	$ 1,370,533.75	$ (24,087.69)	$ 1,346,446.06	$ 1,558.04	$ 10,879.05	$ 12,437.09
	Jul-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 15,945.30	$ 1,368,975.71	$ (25,951.56)	$ 1,343,024.15	$ 1,558.04	$ 10,851.40	$ 12,409.44
	Aug-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 17,503.34	$ 1,367,417.67	$ (27,815.43)	$ 1,339,602.24	$ 1,558.04	$ 10,823.75	$ 12,381.79
	Sep-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 19,061.38	$ 1,365,859.63	$ (29,679.30)	$ 1,336,180.33	$ 1,558.04	$ 10,796.10	$ 12,354.14
	Oct-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 20,619.42	$ 1,364,301.59	$ (31,543.17)	$ 1,332,758.42	$ 1,558.04	$ 10,768.45	$ 12,326.49
	Nov-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 22,177.46	$ 1,362,743.55	$ (33,407.04)	$ 1,329,336.51	$ 1,558.04	$ 10,740.81	$ 12,298.85
	Dec-24	$ -	$ 1,384,921.01	$ 1,558.04	$ 23,735.50	$ 1,361,185.51	$ (35,270.91)	$ 1,325,914.60	$ 1,558.04	$ 10,713.16	$ 12,271.20
2025	Jan-25	$ -	$ 1,384,921.01	$ 1,558.04	$ 25,293.54	$ 1,359,627.47	$ (36,962.66)	$ 1,322,664.81	$ 1,558.04	$ 10,686.90	$ 12,244.94
	Feb-25	$ -	$ 1,384,921.01	$ 1,558.04	$ 26,851.58	$ 1,358,069.43	$ (38,654.41)	$ 1,319,415.02	$ 1,558.04	$ 10,660.64	$ 12,218.68
	Mar-25	$ -	$ 1,384,921.01	$ 1,558.04	$ 28,409.62	$ 1,356,511.39	$ (40,346.16)	$ 1,316,165.23	$ 1,558.04	$ 10,634.38	$ 12,192.42
	Apr-25	$ -	$ 1,384,921.01	$ 1,558.04	$ 29,967.66	$ 1,354,953.35	$ (42,037.91)	$ 1,312,915.44	$ 1,558.04	$ 10,608.13	$ 12,166.17
	May-25	$ -	$ 1,384,921.01	$ 1,558.04	$ 31,525.70	$ 1,353,395.31	$ (43,729.66)	$ 1,309,665.65	$ 1,558.04	$ 10,581.87	$ 12,139.91
	Jun-25	$ -	$ 1,384,921.01	$ 1,558.04	$ 33,083.74	$ 1,351,837.27	$ (45,421.41)	$ 1,306,415.86	$ 1,558.04	$ 10,555.61	$ 12,113.65
	Jul-25	$ 116,118.92	$ 1,501,039.93	$ 1,623.35	$ 34,707.09	$ 1,466,332.84	$ (47,294.89)	$ 1,419,037.95	$ 1,623.35	$ 11,465.58	$ 13,088.93
	Aug-25	$ 199,281.75	$ 1,700,321.68	$ 1,800.77	$ 36,507.86	$ 1,663,813.82	$ (49,530.83)	$ 1,614,282.99	$ 1,800.77	$ 13,043.12	$ 14,843.89
	Sep-25	$ 199,281.75	$ 1,899,603.43	$ 2,024.96	$ 38,532.82	$ 1,861,070.61	$ (52,219.18)	$ 1,808,851.43	$ 2,024.96	$ 14,615.20	$ 16,640.16
	Oct-25	$ 199,281.75	$ 2,098,885.18	$ 2,249.15	$ 40,781.97	$ 2,058,103.21	$ (55,531.30)	$ 2,002,571.91	$ 2,249.15	$ 16,180.43	$ 18,429.58
	Nov-25	$ 48,828.42	$ 2,147,713.60	$ 2,388.71	$ 43,170.68	$ 2,104,542.92	$ (59,056.95)	$ 2,045,485.97	$ 2,388.71	$ 16,527.17	$ 18,915.88
	Dec-25	$ 48,828.42	$ 2,196,542.02	$ 2,443.64	$ 45,614.32	$ 2,150,927.70	$ (63,071.35)	$ 2,087,856.35	$ 2,443.64	$ 16,869.51	$ 19,313.15
2026	Jan-26	$ -	$ 2,196,542.02	$ 2,471.11	$ 48,085.43	$ 2,148,456.59	$ (65,696.62)	$ 2,082,759.97	$ 2,471.11	$ 16,828.34	$ 19,299.45
	Feb-26	$ -	$ 2,196,542.02	$ 2,471.11	$ 50,556.54	$ 2,145,985.48	$ (68,321.89)	$ 2,077,663.59	$ 2,471.11	$ 16,787.16	$ 19,258.27
	Mar-26	$ -	$ 2,196,542.02	$ 2,471.11	$ 53,027.65	$ 2,143,514.37	$ (70,947.16)	$ 2,072,567.21	$ 2,471.11	$ 16,745.98	$ 19,217.09
	Apr-26	$ -	$ 2,196,542.02	$ 2,471.11	$ 55,498.76	$ 2,141,043.26	$ (73,572.43)	$ 2,067,470.83	$ 2,471.11	$ 16,704.80	$ 19,175.91
	May-26	$ -	$ 2,196,542.02	$ 2,471.11	$ 57,969.87	$ 2,138,572.15	$ (76,197.70)	$ 2,062,374.45	$ 2,471.11	$ 16,663.62	$ 19,134.73
	Jun-26	$ -	$ 2,196,542.02	$ 2,471.11	$ 60,440.98	$ 2,136,101.04	$ (78,822.97)	$ 2,057,278.07	$ 2,471.11	$ 16,622.45	$ 19,093.56
	Jul-26	$ 116,118.92	$ 2,312,660.94	$ 2,536.43	$ 62,977.41	$ 2,249,683.53	$ (81,629.97)	$ 2,168,053.56	$ 2,536.43	$ 17,517.49	$ 20,053.92
	Aug-26	$ 199,281.75	$ 2,511,942.69	$ 2,713.84	$ 65,691.25	$ 2,446,251.44	$ (84,799.43)	$ 2,361,452.01	$ 2,713.84	$ 19,080.12	$ 21,793.96
	Sep-26	$ 199,281.75	$ 2,711,224.44	$ 2,938.03	$ 68,629.28	$ 2,642,595.16	$ (88,421.30)	$ 2,554,173.86	$ 2,938.03	$ 20,637.28	$ 23,575.31
	Oct-26	$ 199,281.75	$ 2,910,506.19	$ 3,162.22	$ 71,791.50	$ 2,838,714.69	$ (92,666.94)	$ 2,746,047.75	$ 3,162.22	$ 22,187.58	$ 25,349.80
	Nov-26	$ 48,828.42	$ 2,959,334.61	$ 3,301.79	$ 75,093.29	$ 2,884,241.32	$ (97,126.11)	$ 2,787,115.21	$ 3,301.79	$ 22,519.40	$ 25,821.19
	Dec-26	$ 48,828.42	$ 3,008,163.03	$ 3,356.72	$ 78,450.01	$ 2,929,713.02	$ (102,074.03)	$ 2,827,638.99	$ 3,356.72	$ 22,846.83	$ 26,203.55
2027	Jan-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 81,834.19	$ 2,926,328.84	$ (105,543.37)	$ 2,820,785.47	$ 3,384.18	$ 22,791.45	$ 26,175.63
	Feb-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 85,218.37	$ 2,922,944.66	$ (109,012.71)	$ 2,813,931.95	$ 3,384.18	$ 22,736.08	$ 26,120.26
	Mar-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 88,602.55	$ 2,919,560.48	$ (112,482.05)	$ 2,807,078.43	$ 3,384.18	$ 22,680.70	$ 26,064.88
	Apr-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 91,986.73	$ 2,916,176.30	$ (115,951.39)	$ 2,800,224.91	$ 3,384.18	$ 22,625.33	$ 26,009.51
	May-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 95,370.91	$ 2,912,792.12	$ (119,420.73)	$ 2,793,371.39	$ 3,384.18	$ 22,569.95	$ 25,954.13
	Jun-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 98,755.09	$ 2,909,407.94	$ (122,890.07)	$ 2,786,517.87	$ 3,384.18	$ 22,514.58	$ 25,898.76
	Jul-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 102,139.27	$ 2,906,023.76	$ (126,359.41)	$ 2,779,664.35	$ 3,384.18	$ 22,459.20	$ 25,843.38
	Aug-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 105,523.45	$ 2,902,639.58	$ (129,828.75)	$ 2,772,810.83	$ 3,384.18	$ 22,403.83	$ 25,788.01
	Sep-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 108,907.63	$ 2,899,255.40	$ (133,298.09)	$ 2,765,957.31	$ 3,384.18	$ 22,348.45	$ 25,732.63
	Oct-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 112,291.81	$ 2,895,871.22	$ (136,767.43)	$ 2,759,103.79	$ 3,384.18	$ 22,293.07	$ 25,677.25
	Nov-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 115,675.99	$ 2,892,487.04	$ (140,236.77)	$ 2,752,250.27	$ 3,384.18	$ 22,237.70	$ 25,621.88
	Dec-27	$ -	$ 3,008,163.03	$ 3,384.18	$ 119,060.17	$ 2,889,102.86	$ (143,706.11)	$ 2,745,396.75	$ 3,384.18	$ 22,182.32	$ 25,566.50

2023 Total =	$ 1,384,921.00	2023 Annual Revenue Requirement =	$ 48,766.90
2024 Total =	$ -	2024 Annual Revenue Requirement =	$ 149,079.16
2025 Total =	$ 811,621.00	2025 Annual Revenue Requirement =	$ 174,307.36
2026 Total =	$ 811,621.00	2026 Annual Revenue Requirement =	$ 257,976.74
2027 Total =	$ -	2027 Annual Revenue Requirement =	$ 310,452.82

[1]per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
Resiliency Revenue Requirement Calculation
Station Equipment

Reg Depreciation	1.08%	FERC Account 362 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	1.35%	FERC Account 362 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	*[b]*	*[c]*	*[d]*	*[e]*	*[f]*	*[g]=[d]-[f]*	*[n]*	*[o]=[g]+[n]*	*[p]=[e]*	*[q]*	*[r]=[p]+[q]*
2023	Jan-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feb-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mar-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Apr-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	May-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jun-23	$ 185.23	$ 185.23	$ 0.08	$ 0.08	$ 185.15	$ (0.25)	$ 184.90	$ 0.08	$ 1.40	$ 1.48
	Jul-23	$ 185.23	$ 370.46	$ 0.25	$ 0.33	$ 370.13	$ (0.77)	$ 369.36	$ 0.25	$ 2.80	$ 3.05
	Aug-23	$ 555.69	$ 926.15	$ 0.58	$ 0.91	$ 925.24	$ (2.35)	$ 922.89	$ 0.58	$ 6.99	$ 7.57
	Sep-23	$ 370.46	$ 1,296.61	$ 1.00	$ 1.91	$ 1,294.70	$ (4.77)	$ 1,289.93	$ 1.00	$ 9.77	$ 10.77
	Oct-23	$ 370.46	$ 1,667.07	$ 1.33	$ 3.24	$ 1,663.83	$ (8.37)	$ 1,655.46	$ 1.33	$ 12.53	$ 13.86
	Nov-23	$ 185.23	$ 1,852.30	$ 1.98	$ 5.22	$ 1,847.08	$ (12.75)	$ 1,834.33	$ 1.98	$ 14.82	$ 16.80
	Dec-23	$ -	$ 1,852.30	$ 2.08	$ 7.30	$ 1,845.00	$ (17.10)	$ 1,827.90	$ 2.08	$ 14.77	$ 16.85
2024	Jan-24	$ -	$ 1,852.30	$ 2.08	$ 9.38	$ 1,842.92	$ (19.59)	$ 1,823.33	$ 2.08	$ 14.73	$ 16.81
	Feb-24	$ -	$ 1,852.30	$ 2.08	$ 11.46	$ 1,840.84	$ (22.08)	$ 1,818.76	$ 2.08	$ 14.70	$ 16.78
	Mar-24	$ -	$ 1,852.30	$ 2.08	$ 13.54	$ 1,838.76	$ (24.57)	$ 1,814.19	$ 2.08	$ 14.66	$ 16.74
	Apr-24	$ -	$ 1,852.30	$ 2.08	$ 15.62	$ 1,836.68	$ (27.06)	$ 1,809.62	$ 2.08	$ 14.62	$ 16.70
	May-24	$ -	$ 1,852.30	$ 2.08	$ 17.70	$ 1,834.60	$ (29.55)	$ 1,805.05	$ 2.08	$ 14.58	$ 16.66
	Jun-24	$ 185.23	$ 2,037.53	$ 2.19	$ 19.89	$ 2,017.64	$ (32.29)	$ 1,985.35	$ 2.19	$ 16.04	$ 18.23
	Jul-24	$ 185.23	$ 2,222.76	$ 2.40	$ 22.29	$ 2,200.47	$ (35.29)	$ 2,165.18	$ 2.40	$ 17.49	$ 19.89
	Aug-24	$ 555.69	$ 2,778.45	$ 2.81	$ 25.10	$ 2,753.35	$ (39.32)	$ 2,714.03	$ 2.81	$ 21.93	$ 24.74
	Sep-24	$ 370.46	$ 3,148.91	$ 3.33	$ 28.43	$ 3,120.48	$ (44.16)	$ 3,076.32	$ 3.33	$ 24.86	$ 28.19
	Oct-24	$ 370.46	$ 3,519.37	$ 3.75	$ 32.18	$ 3,487.19	$ (50.16)	$ 3,437.03	$ 3.75	$ 27.77	$ 31.52
	Nov-24	$ 185.23	$ 3,704.60	$ 4.06	$ 36.24	$ 3,668.36	$ (57.03)	$ 3,611.33	$ 4.06	$ 29.18	$ 33.24
	Dec-24	$ -	$ 3,704.60	$ 4.17	$ 40.41	$ 3,664.19	$ (63.87)	$ 3,600.32	$ 4.17	$ 29.09	$ 33.26
2025	Jan-25	$ -	$ 3,704.60	$ 4.17	$ 44.58	$ 3,660.02	$ (68.63)	$ 3,591.39	$ 4.17	$ 29.02	$ 33.19
	Feb-25	$ -	$ 3,704.60	$ 4.17	$ 48.75	$ 3,655.85	$ (73.39)	$ 3,582.46	$ 4.17	$ 28.95	$ 33.12
	Mar-25	$ -	$ 3,704.60	$ 4.17	$ 52.92	$ 3,651.68	$ (78.15)	$ 3,573.53	$ 4.17	$ 28.87	$ 33.04
	Apr-25	$ -	$ 3,704.60	$ 4.17	$ 57.09	$ 3,647.51	$ (82.91)	$ 3,564.60	$ 4.17	$ 28.80	$ 32.97
	May-25	$ -	$ 3,704.60	$ 4.17	$ 61.26	$ 3,643.34	$ (87.67)	$ 3,555.67	$ 4.17	$ 28.73	$ 32.90
	Jun-25	$ 185.23	$ 3,889.83	$ 4.27	$ 65.53	$ 3,824.30	$ (92.67)	$ 3,731.63	$ 4.27	$ 30.15	$ 34.42
	Jul-25	$ 185.23	$ 4,075.06	$ 4.48	$ 70.01	$ 4,005.05	$ (97.93)	$ 3,907.12	$ 4.48	$ 31.57	$ 36.05
	Aug-25	$ 555.69	$ 4,630.75	$ 4.90	$ 74.91	$ 4,555.84	$ (104.22)	$ 4,451.62	$ 4.90	$ 35.97	$ 40.87
	Sep-25	$ 370.46	$ 5,001.21	$ 5.42	$ 80.33	$ 4,920.88	$ (111.33)	$ 4,809.55	$ 5.42	$ 38.86	$ 44.28
	Oct-25	$ 370.46	$ 5,371.67	$ 5.83	$ 86.16	$ 5,285.51	$ (119.60)	$ 5,165.91	$ 5.83	$ 41.74	$ 47.57
	Nov-25	$ 185.23	$ 5,556.90	$ 6.15	$ 92.31	$ 5,464.59	$ (128.73)	$ 5,335.86	$ 6.15	$ 43.11	$ 49.26
	Dec-25	$ -	$ 5,556.90	$ 6.25	$ 98.56	$ 5,458.34	$ (137.84)	$ 5,320.50	$ 6.25	$ 42.99	$ 49.24
2026	Jan-26	$ -	$ 5,556.90	$ 6.25	$ 104.81	$ 5,452.09	$ (144.65)	$ 5,307.44	$ 6.25	$ 42.88	$ 49.13
	Feb-26	$ -	$ 5,556.90	$ 6.25	$ 111.06	$ 5,445.84	$ (151.46)	$ 5,294.38	$ 6.25	$ 42.78	$ 49.03
	Mar-26	$ -	$ 5,556.90	$ 6.25	$ 117.31	$ 5,439.59	$ (158.27)	$ 5,281.32	$ 6.25	$ 42.67	$ 48.92
	Apr-26	$ -	$ 5,556.90	$ 6.25	$ 123.56	$ 5,433.34	$ (165.08)	$ 5,268.26	$ 6.25	$ 42.57	$ 48.82
	May-26	$ -	$ 5,556.90	$ 6.25	$ 129.81	$ 5,427.09	$ (171.89)	$ 5,255.20	$ 6.25	$ 42.46	$ 48.71
	Jun-26	$ 185.23	$ 5,742.13	$ 6.36	$ 136.17	$ 5,605.96	$ (178.94)	$ 5,427.02	$ 6.36	$ 43.85	$ 50.21
	Jul-26	$ 185.23	$ 5,927.36	$ 6.56	$ 142.73	$ 5,784.63	$ (186.25)	$ 5,598.38	$ 6.56	$ 45.23	$ 51.79
	Aug-26	$ 555.69	$ 6,483.05	$ 6.98	$ 149.71	$ 6,333.34	$ (194.59)	$ 6,138.75	$ 6.98	$ 49.60	$ 56.58
	Sep-26	$ 370.46	$ 6,853.51	$ 7.50	$ 157.21	$ 6,696.30	$ (203.75)	$ 6,492.55	$ 7.50	$ 52.46	$ 59.96
	Oct-26	$ 370.46	$ 7,223.97	$ 7.92	$ 165.13	$ 7,058.84	$ (214.06)	$ 6,844.78	$ 7.92	$ 55.30	$ 63.22
	Nov-26	$ 185.23	$ 7,409.20	$ 8.23	$ 173.36	$ 7,235.84	$ (225.24)	$ 7,010.60	$ 8.23	$ 56.64	$ 64.87
	Dec-26	$ -	$ 7,409.20	$ 8.34	$ 181.70	$ 7,227.50	$ (236.39)	$ 6,991.11	$ 8.34	$ 56.49	$ 64.83
2027	Jan-27	$ -	$ 7,409.20	$ 8.34	$ 190.04	$ 7,219.16	$ (245.05)	$ 6,974.11	$ 8.34	$ 56.35	$ 64.69
	Feb-27	$ -	$ 7,409.20	$ 8.34	$ 198.38	$ 7,210.82	$ (253.71)	$ 6,957.11	$ 8.34	$ 56.21	$ 64.55
	Mar-27	$ -	$ 7,409.20	$ 8.34	$ 206.72	$ 7,202.48	$ (262.37)	$ 6,940.11	$ 8.34	$ 56.07	$ 64.41
	Apr-27	$ -	$ 7,409.20	$ 8.34	$ 215.06	$ 7,194.14	$ (271.03)	$ 6,923.11	$ 8.34	$ 55.94	$ 64.28
	May-27	$ -	$ 7,409.20	$ 8.34	$ 223.40	$ 7,185.80	$ (279.69)	$ 6,906.11	$ 8.34	$ 55.80	$ 64.14
	Jun-27	$ 185.23	$ 7,594.43	$ 8.44	$ 231.84	$ 7,362.59	$ (288.59)	$ 7,074.00	$ 8.44	$ 57.16	$ 65.60
	Jul-27	$ 185.23	$ 7,779.66	$ 8.65	$ 240.49	$ 7,539.17	$ (297.75)	$ 7,241.42	$ 8.65	$ 58.51	$ 67.16
	Aug-27	$ 555.69	$ 8,335.35	$ 9.06	$ 249.55	$ 8,085.80	$ (307.95)	$ 7,777.85	$ 9.06	$ 62.84	$ 71.90
	Sep-27	$ 370.46	$ 8,705.81	$ 9.59	$ 259.14	$ 8,446.67	$ (318.96)	$ 8,127.71	$ 9.59	$ 65.67	$ 75.26
	Oct-27	$ 370.46	$ 9,076.27	$ 10.00	$ 269.14	$ 8,807.13	$ (331.13)	$ 8,476.00	$ 10.00	$ 68.48	$ 78.48
	Nov-27	$ 185.23	$ 9,261.50	$ 10.31	$ 279.45	$ 8,982.05	$ (344.17)	$ 8,637.88	$ 10.31	$ 69.79	$ 80.10
	Dec-27	$ -	$ 9,261.50	$ 10.42	$ 289.87	$ 8,971.63	$ (357.18)	$ 8,614.45	$ 10.42	$ 69.60	$ 80.02

2023 Total =	$ 1,852.30	2023 Annual Revenue Requirement =	$ 70.38
2024 Total =	$ 1,852.30	2024 Annual Revenue Requirement =	$ 272.76
2025 Total =	$ 1,852.30	2025 Annual Revenue Requirement =	$ 466.91
2026 Total =	$ 1,852.30	2026 Annual Revenue Requirement =	$ 656.07
2027 Total =	$ 1,852.30	2027 Annual Revenue Requirement =	$ 840.59

[1]per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
Resiliency Revenue Requirement Calculation
Pole, Tower, Fixture

Reg Depreciation	1.30%	FERC Account 364 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	1.81%	FERC Account 364 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	*[b]*	*[c]*	*[d]*	*[e]*	*[f]*	*[g]=[d]-[f]*	*[n]*	*[o]=[g]+[n]*	*[p]=[e]*	*[q]*	*[r]=[p]+[q]*
2023	Jan-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feb-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mar-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Apr-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	May-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jun-23	$ 38,996.28	$ 38,996.28	$ 21.12	$ 21.12	$ 38,975.16	$ (51.68)	$ 38,923.48	$ 21.12	$ 294.72	$ 315.84
	Jul-23	$ 38,996.28	$ 77,992.56	$ 63.37	$ 84.49	$ 77,908.07	$ (158.80)	$ 77,749.27	$ 63.37	$ 588.70	$ 652.07
	Aug-23	$ 116,988.83	$ 194,981.39	$ 147.86	$ 232.35	$ 194,749.04	$ (484.11)	$ 194,264.93	$ 147.86	$ 1,470.94	$ 1,618.80
	Sep-23	$ 77,992.55	$ 272,973.94	$ 253.48	$ 485.83	$ 272,488.11	$ (981.56)	$ 271,506.55	$ 253.48	$ 2,055.80	$ 2,309.28
	Oct-23	$ 77,992.55	$ 350,966.49	$ 337.97	$ 823.80	$ 350,142.69	$ (1,724.03)	$ 348,418.66	$ 337.97	$ 2,638.16	$ 2,976.13
	Nov-23	$ 38,996.28	$ 389,962.77	$ 558.78	$ 1,382.58	$ 388,580.19	$ (2,606.94)	$ 385,973.25	$ 558.78	$ 3,118.60	$ 3,677.38
	Dec-23	$ -	$ 389,962.77	$ 588.19	$ 1,970.77	$ 387,992.00	$ (3,481.76)	$ 384,510.24	$ 588.19	$ 3,106.78	$ 3,694.97
2024	Jan-24	$ -	$ 389,962.77	$ 588.19	$ 2,558.96	$ 387,403.81	$ (3,965.45)	$ 383,438.36	$ 588.19	$ 3,098.11	$ 3,686.30
	Feb-24	$ -	$ 389,962.77	$ 588.19	$ 3,147.15	$ 386,815.62	$ (4,449.14)	$ 382,366.48	$ 588.19	$ 3,089.45	$ 3,677.64
	Mar-24	$ -	$ 389,962.77	$ 588.19	$ 3,735.34	$ 386,227.43	$ (4,932.83)	$ 381,294.60	$ 588.19	$ 3,080.79	$ 3,668.98
	Apr-24	$ -	$ 389,962.77	$ 588.19	$ 4,323.53	$ 385,639.24	$ (5,416.52)	$ 380,222.72	$ 588.19	$ 3,072.13	$ 3,660.32
	May-24	$ -	$ 389,962.77	$ 588.19	$ 4,911.72	$ 385,051.05	$ (5,900.21)	$ 379,150.84	$ 588.19	$ 3,063.47	$ 3,651.66
	Jun-24	$ 38,996.28	$ 428,959.05	$ 617.60	$ 5,529.32	$ 423,429.73	$ (6,433.30)	$ 416,996.43	$ 617.60	$ 3,369.26	$ 3,986.86
	Jul-24	$ 38,996.28	$ 467,955.33	$ 676.42	$ 6,205.74	$ 461,749.59	$ (7,017.27)	$ 454,732.32	$ 676.42	$ 3,674.16	$ 4,350.58
	Aug-24	$ 116,988.83	$ 584,944.16	$ 794.06	$ 6,999.80	$ 577,944.36	$ (7,810.31)	$ 570,134.05	$ 794.06	$ 4,606.58	$ 5,400.64
	Sep-24	$ 77,992.55	$ 662,936.71	$ 941.11	$ 7,940.91	$ 654,995.80	$ (8,764.09)	$ 646,231.71	$ 941.11	$ 5,221.44	$ 6,162.55
	Oct-24	$ 77,992.55	$ 740,929.26	$ 1,058.75	$ 8,999.66	$ 731,929.60	$ (9,953.77)	$ 721,975.83	$ 1,058.75	$ 5,833.44	$ 6,892.19
	Nov-24	$ 38,996.28	$ 779,925.54	$ 1,146.98	$ 10,146.64	$ 769,778.90	$ (11,320.37)	$ 758,458.53	$ 1,146.98	$ 6,128.21	$ 7,275.19
	Dec-24	$ -	$ 779,925.54	$ 1,176.39	$ 11,323.03	$ 768,602.51	$ (12,678.88)	$ 755,923.63	$ 1,176.39	$ 6,107.73	$ 7,284.12
2025	Jan-25	$ -	$ 779,925.54	$ 1,176.39	$ 12,499.42	$ 767,426.12	$ (13,597.79)	$ 753,828.33	$ 1,176.39	$ 6,090.80	$ 7,267.19
	Feb-25	$ -	$ 779,925.54	$ 1,176.39	$ 13,675.81	$ 766,249.73	$ (14,516.70)	$ 751,733.03	$ 1,176.39	$ 6,073.87	$ 7,250.26
	Mar-25	$ -	$ 779,925.54	$ 1,176.39	$ 14,852.20	$ 765,073.34	$ (15,435.61)	$ 749,637.73	$ 1,176.39	$ 6,056.94	$ 7,233.33
	Apr-25	$ -	$ 779,925.54	$ 1,176.39	$ 16,028.59	$ 763,896.95	$ (16,354.52)	$ 747,542.43	$ 1,176.39	$ 6,040.01	$ 7,216.40
	May-25	$ -	$ 779,925.54	$ 1,176.39	$ 17,204.98	$ 762,720.56	$ (17,273.43)	$ 745,447.13	$ 1,176.39	$ 6,023.08	$ 7,199.47
	Jun-25	$ 38,996.28	$ 818,921.82	$ 1,205.80	$ 18,410.78	$ 800,511.04	$ (18,241.74)	$ 782,269.30	$ 1,205.80	$ 6,320.60	$ 7,526.40
	Jul-25	$ 38,996.28	$ 857,918.10	$ 1,264.62	$ 19,675.40	$ 838,242.70	$ (19,260.93)	$ 818,981.77	$ 1,264.62	$ 6,617.23	$ 7,881.85
	Aug-25	$ 116,988.83	$ 974,906.93	$ 1,382.26	$ 21,057.66	$ 953,849.27	$ (20,489.19)	$ 933,360.08	$ 1,382.26	$ 7,541.39	$ 8,923.65
	Sep-25	$ 77,992.55	$ 1,052,899.48	$ 1,529.30	$ 22,586.96	$ 1,030,312.52	$ (21,878.19)	$ 1,008,434.33	$ 1,529.30	$ 8,147.97	$ 9,677.27
	Oct-25	$ 77,992.55	$ 1,130,892.03	$ 1,646.94	$ 24,233.90	$ 1,106,658.13	$ (23,503.09)	$ 1,083,155.04	$ 1,646.94	$ 8,751.70	$ 10,398.64
	Nov-25	$ 38,996.28	$ 1,169,888.31	$ 1,735.17	$ 25,969.07	$ 1,143,919.24	$ (25,304.92)	$ 1,118,614.32	$ 1,735.17	$ 9,038.21	$ 10,773.38
	Dec-25	$ -	$ 1,169,888.31	$ 1,764.58	$ 27,733.65	$ 1,142,154.66	$ (27,098.65)	$ 1,115,056.01	$ 1,764.58	$ 9,009.46	$ 10,774.04
2026	Jan-26	$ -	$ 1,169,888.31	$ 1,764.58	$ 29,498.23	$ 1,140,390.08	$ (28,408.08)	$ 1,111,982.00	$ 1,764.58	$ 8,984.62	$ 10,749.20
	Feb-26	$ -	$ 1,169,888.31	$ 1,764.58	$ 31,262.81	$ 1,138,625.50	$ (29,717.51)	$ 1,108,907.99	$ 1,764.58	$ 8,959.78	$ 10,724.36
	Mar-26	$ -	$ 1,169,888.31	$ 1,764.58	$ 33,027.39	$ 1,136,860.92	$ (31,026.94)	$ 1,105,833.98	$ 1,764.58	$ 8,934.94	$ 10,699.52
	Apr-26	$ -	$ 1,169,888.31	$ 1,764.58	$ 34,791.97	$ 1,135,096.34	$ (32,336.37)	$ 1,102,759.97	$ 1,764.58	$ 8,910.11	$ 10,674.69
	May-26	$ -	$ 1,169,888.31	$ 1,764.58	$ 36,556.55	$ 1,133,331.76	$ (33,645.80)	$ 1,099,685.96	$ 1,764.58	$ 8,885.27	$ 10,649.85
	Jun-26	$ 38,996.28	$ 1,208,884.59	$ 1,793.99	$ 38,350.54	$ 1,170,534.05	$ (35,004.62)	$ 1,135,529.43	$ 1,793.99	$ 9,174.88	$ 10,968.87
	Jul-26	$ 38,996.28	$ 1,247,880.87	$ 1,852.81	$ 40,203.35	$ 1,207,677.52	$ (36,414.32)	$ 1,171,263.20	$ 1,852.81	$ 9,463.60	$ 11,316.41
	Aug-26	$ 116,988.83	$ 1,364,869.70	$ 1,970.45	$ 42,173.80	$ 1,322,695.90	$ (38,033.09)	$ 1,284,662.81	$ 1,970.45	$ 10,379.85	$ 12,350.30
	Sep-26	$ 77,992.55	$ 1,442,862.25	$ 2,117.50	$ 44,291.30	$ 1,398,570.95	$ (39,812.60)	$ 1,358,758.35	$ 2,117.50	$ 10,978.53	$ 13,096.03
	Oct-26	$ 77,992.55	$ 1,520,854.80	$ 2,235.14	$ 46,526.44	$ 1,474,328.36	$ (41,828.01)	$ 1,432,500.35	$ 2,235.14	$ 11,574.35	$ 13,809.49
	Nov-26	$ 38,996.28	$ 1,559,851.08	$ 2,323.37	$ 48,849.81	$ 1,511,001.27	$ (44,020.35)	$ 1,466,980.92	$ 2,323.37	$ 11,852.95	$ 14,176.32
	Dec-26	$ -	$ 1,559,851.08	$ 2,352.78	$ 51,202.59	$ 1,508,648.49	$ (46,204.59)	$ 1,462,443.90	$ 2,352.78	$ 11,816.29	$ 14,169.07
2027	Jan-27	$ -	$ 1,559,851.08	$ 2,352.78	$ 53,555.37	$ 1,506,295.71	$ (47,863.03)	$ 1,458,432.68	$ 2,352.78	$ 11,783.88	$ 14,136.66
	Feb-27	$ -	$ 1,559,851.08	$ 2,352.78	$ 55,908.15	$ 1,503,942.93	$ (49,521.47)	$ 1,454,421.46	$ 2,352.78	$ 11,751.47	$ 14,104.25
	Mar-27	$ -	$ 1,559,851.08	$ 2,352.78	$ 58,260.93	$ 1,501,590.15	$ (51,179.91)	$ 1,450,410.24	$ 2,352.78	$ 11,719.06	$ 14,071.84
	Apr-27	$ -	$ 1,559,851.08	$ 2,352.78	$ 60,613.71	$ 1,499,237.37	$ (52,838.35)	$ 1,446,399.02	$ 2,352.78	$ 11,686.65	$ 14,039.43
	May-27	$ -	$ 1,559,851.08	$ 2,352.78	$ 62,966.49	$ 1,496,884.59	$ (54,496.79)	$ 1,442,387.80	$ 2,352.78	$ 11,654.24	$ 14,007.02
	Jun-27	$ 38,996.28	$ 1,598,847.36	$ 2,382.19	$ 65,348.68	$ 1,533,498.68	$ (56,204.63)	$ 1,477,294.05	$ 2,382.19	$ 11,936.28	$ 14,318.47
	Jul-27	$ 38,996.28	$ 1,637,843.64	$ 2,441.00	$ 67,789.68	$ 1,570,053.96	$ (57,963.35)	$ 1,512,090.61	$ 2,441.00	$ 12,217.43	$ 14,658.43
	Aug-27	$ 116,988.83	$ 1,754,832.47	$ 2,558.64	$ 70,348.32	$ 1,684,484.15	$ (59,931.15)	$ 1,624,553.00	$ 2,558.64	$ 13,126.10	$ 15,684.74
	Sep-27	$ 77,992.55	$ 1,832,825.02	$ 2,705.69	$ 73,054.01	$ 1,759,771.01	$ (62,059.68)	$ 1,697,711.33	$ 2,705.69	$ 13,717.21	$ 16,422.90
	Oct-27	$ 77,992.55	$ 1,910,817.57	$ 2,823.33	$ 75,877.34	$ 1,834,940.23	$ (64,424.11)	$ 1,770,516.12	$ 2,823.33	$ 14,305.46	$ 17,128.79
	Nov-27	$ 38,996.28	$ 1,949,813.85	$ 2,911.56	$ 78,788.90	$ 1,871,024.95	$ (66,965.47)	$ 1,804,059.48	$ 2,911.56	$ 14,576.48	$ 17,488.04
	Dec-27	$ -	$ 1,949,813.85	$ 2,940.97	$ 81,729.87	$ 1,868,083.98	$ (69,498.73)	$ 1,798,585.25	$ 2,940.97	$ 14,532.25	$ 17,473.22

2023 Total =	$ 389,962.77	2023 Annual Revenue Requirement =	$ 15,244.47
2024 Total =	$ 389,962.77	2024 Annual Revenue Requirement =	$ 59,697.03
2025 Total =	$ 389,962.77	2025 Annual Revenue Requirement =	$ 102,121.88
2026 Total =	$ 389,962.77	2026 Annual Revenue Requirement =	$ 143,384.11
2027 Total =	$ 389,962.77	2027 Annual Revenue Requirement =	$ 183,533.79

[1]per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
Resiliency Revenue Requirement Calculation
O/H Conduct, Dvcs

Reg Depreciation	1.54%	FERC Account 365 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	2.02%	FERC Account 365 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	2027 Tax Depreciation	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	*[b]*	*[c]*	*[d]*	*[e]*	*[f]*	*[g]=[d]-[f]*		*[n]*	*[o]=[g]+[n]*	*[p]=[e]*	*[q]*	*[r]=[p]+[q]*
2023	Jan-23	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
	Feb-23	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
	Mar-23	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
	Apr-23	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
	May-23	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
	Jun-23	$ 220,987.09	$ 220,987.09	$ 141.80	$ 141.80	$ 220,845.29		$ (286.75)	$ 220,558.54	$ 141.80	$ 1,670.03	$ 1,811.83
	Jul-23	$ 220,987.09	$ 441,974.18	$ 425.40	$ 567.20	$ 441,406.98		$ (875.52)	$ 440,531.46	$ 425.40	$ 3,335.62	$ 3,761.02
	Aug-23	$ 662,961.28	$ 1,104,935.46	$ 992.60	$ 1,559.80	$ 1,103,375.66		$ (2,676.44)	$ 1,100,699.22	$ 992.60	$ 8,334.29	$ 9,326.89
	Sep-23	$ 441,974.19	$ 1,546,909.65	$ 1,701.60	$ 3,261.40	$ 1,543,648.25		$ (5,422.45)	$ 1,538,225.80	$ 1,701.60	$ 11,647.17	$ 13,348.77
	Oct-23	$ 441,974.19	$ 1,988,883.84	$ 2,268.80	$ 5,530.20	$ 1,983,353.64		$ (9,532.64)	$ 1,973,821.00	$ 2,268.80	$ 14,945.41	$ 17,214.21
	Nov-23	$ 220,987.09	$ 2,209,870.93	$ 3,533.95	$ 9,064.15	$ 2,200,806.78		$ (14,434.88)	$ 2,186,371.90	$ 3,533.95	$ 17,665.50	$ 21,199.45
	Dec-23	$ -	$ 2,209,870.93	$ 3,719.95	$ 12,784.10	$ 2,197,086.83		$ (19,285.94)	$ 2,177,800.89	$ 3,719.95	$ 17,596.25	$ 21,316.20
2024	Jan-24	$ -	$ 2,209,870.93	$ 3,719.95	$ 16,504.05	$ 2,193,366.88		$ (21,920.54)	$ 2,171,446.34	$ 3,719.95	$ 17,544.91	$ 21,264.86
	Feb-24	$ -	$ 2,209,870.93	$ 3,719.95	$ 20,224.00	$ 2,189,646.93		$ (24,555.14)	$ 2,165,091.79	$ 3,719.95	$ 17,493.56	$ 21,213.51
	Mar-24	$ -	$ 2,209,870.93	$ 3,719.95	$ 23,943.95	$ 2,185,926.98		$ (27,189.74)	$ 2,158,737.24	$ 3,719.95	$ 17,442.22	$ 21,162.17
	Apr-24	$ -	$ 2,209,870.93	$ 3,719.95	$ 27,663.90	$ 2,182,207.03		$ (29,824.34)	$ 2,152,382.69	$ 3,719.95	$ 17,390.87	$ 21,110.82
	May-24	$ -	$ 2,209,870.93	$ 3,719.95	$ 31,383.85	$ 2,178,487.08		$ (32,458.94)	$ 2,146,028.14	$ 3,719.95	$ 17,339.53	$ 21,059.48
	Jun-24	$ 220,987.09	$ 2,430,858.02	$ 3,905.95	$ 35,289.80	$ 2,395,568.22		$ (35,368.13)	$ 2,360,200.09	$ 3,905.95	$ 19,070.00	$ 22,975.95
	Jul-24	$ 220,987.09	$ 2,651,845.11	$ 4,277.94	$ 39,567.74	$ 2,612,277.37		$ (38,555.02)	$ 2,573,722.35	$ 4,277.94	$ 20,795.23	$ 25,073.17
	Aug-24	$ 662,961.28	$ 3,314,806.39	$ 5,021.93	$ 44,589.67	$ 3,270,216.72		$ (42,905.41)	$ 3,227,311.31	$ 5,021.93	$ 26,076.11	$ 31,098.04
	Sep-24	$ 441,974.19	$ 3,756,780.58	$ 5,951.92	$ 50,541.59	$ 3,706,238.99		$ (48,140.08)	$ 3,658,098.91	$ 5,951.92	$ 29,556.80	$ 35,508.72
	Oct-24	$ 441,974.19	$ 4,198,754.77	$ 6,695.91	$ 57,237.50	$ 4,141,517.27		$ (54,690.27)	$ 4,086,827.00	$ 6,695.91	$ 33,020.85	$ 39,716.76
	Nov-24	$ 220,987.09	$ 4,419,741.86	$ 7,253.90	$ 64,491.40	$ 4,355,250.46		$ (62,227.11)	$ 4,293,023.35	$ 7,253.90	$ 34,686.88	$ 41,940.78
	Dec-24	$ -	$ 4,419,741.86	$ 7,439.90	$ 71,931.30	$ 4,347,810.56		$ (69,712.77)	$ 4,278,097.79	$ 7,439.90	$ 34,566.28	$ 42,006.18
2025	Jan-25	$ -	$ 4,419,741.86	$ 7,439.90	$ 79,371.20	$ 4,340,370.66		$ (74,707.31)	$ 4,265,663.35	$ 7,439.90	$ 34,465.81	$ 41,905.71
	Feb-25	$ -	$ 4,419,741.86	$ 7,439.90	$ 86,811.10	$ 4,332,930.76		$ (79,701.85)	$ 4,253,228.91	$ 7,439.90	$ 34,365.34	$ 41,805.24
	Mar-25	$ -	$ 4,419,741.86	$ 7,439.90	$ 94,251.00	$ 4,325,490.86		$ (84,696.39)	$ 4,240,794.47	$ 7,439.90	$ 34,264.88	$ 41,704.78
	Apr-25	$ -	$ 4,419,741.86	$ 7,439.90	$ 101,690.90	$ 4,318,050.96		$ (89,690.93)	$ 4,228,360.03	$ 7,439.90	$ 34,164.41	$ 41,604.31
	May-25	$ -	$ 4,419,741.86	$ 7,439.90	$ 109,130.80	$ 4,310,611.06		$ (94,685.47)	$ 4,215,925.59	$ 7,439.90	$ 34,063.94	$ 41,503.84
	Jun-25	$ 220,987.09	$ 4,640,728.95	$ 7,625.90	$ 116,756.70	$ 4,523,972.25		$ (99,954.60)	$ 4,424,017.65	$ 7,625.90	$ 35,745.29	$ 43,371.19
	Jul-25	$ 220,987.09	$ 4,861,716.04	$ 7,997.89	$ 124,754.59	$ 4,736,961.45		$ (105,501.43)	$ 4,631,460.02	$ 7,997.89	$ 37,421.38	$ 45,419.27
	Aug-25	$ 662,961.28	$ 5,524,677.32	$ 8,741.88	$ 133,496.47	$ 5,391,180.85		$ (112,211.76)	$ 5,278,969.09	$ 8,741.88	$ 42,653.14	$ 51,395.02
	Sep-25	$ 441,974.19	$ 5,966,651.51	$ 9,671.87	$ 143,168.34	$ 5,823,483.17		$ (119,806.37)	$ 5,703,676.80	$ 9,671.87	$ 46,084.71	$ 55,756.58
	Oct-25	$ 441,974.19	$ 6,408,625.70	$ 10,415.86	$ 153,584.20	$ 6,255,041.50		$ (128,716.50)	$ 6,126,325.00	$ 10,415.86	$ 49,499.63	$ 59,915.49
	Nov-25	$ 220,987.09	$ 6,629,612.79	$ 10,973.85	$ 164,558.05	$ 6,465,054.74		$ (138,613.28)	$ 6,326,441.46	$ 10,973.85	$ 51,116.54	$ 62,090.39
	Dec-25	$ -	$ 6,629,612.79	$ 11,159.85	$ 175,717.90	$ 6,453,894.89		$ (148,458.88)	$ 6,305,436.01	$ 11,159.85	$ 50,946.82	$ 62,106.67
2026	Jan-26	$ -	$ 6,629,612.79	$ 11,159.85	$ 186,877.75	$ 6,442,735.04		$ (155,559.98)	$ 6,287,175.06	$ 11,159.85	$ 50,799.27	$ 61,959.12
	Feb-26	$ -	$ 6,629,612.79	$ 11,159.85	$ 198,037.60	$ 6,431,575.19		$ (162,661.08)	$ 6,268,914.11	$ 11,159.85	$ 50,651.73	$ 61,811.58
	Mar-26	$ -	$ 6,629,612.79	$ 11,159.85	$ 209,197.45	$ 6,420,415.34		$ (169,762.18)	$ 6,250,653.16	$ 11,159.85	$ 50,504.18	$ 61,664.03
	Apr-26	$ -	$ 6,629,612.79	$ 11,159.85	$ 220,357.30	$ 6,409,255.49		$ (176,863.28)	$ 6,232,392.21	$ 11,159.85	$ 50,356.64	$ 61,516.49
	May-26	$ -	$ 6,629,612.79	$ 11,159.85	$ 231,517.15	$ 6,398,095.64		$ (183,964.38)	$ 6,214,131.26	$ 11,159.85	$ 50,209.09	$ 61,368.94
	Jun-26	$ 220,987.09	$ 6,850,599.88	$ 11,345.85	$ 242,863.00	$ 6,607,736.88		$ (191,340.07)	$ 6,416,396.81	$ 11,345.85	$ 51,843.36	$ 63,189.21
	Jul-26	$ 220,987.09	$ 7,071,586.97	$ 11,717.84	$ 254,580.84	$ 6,817,006.13		$ (198,993.46)	$ 6,618,012.67	$ 11,717.84	$ 53,472.38	$ 65,190.22
	Aug-26	$ 662,961.28	$ 7,734,548.25	$ 12,461.83	$ 267,042.67	$ 7,467,505.58		$ (207,810.35)	$ 7,259,695.23	$ 12,461.83	$ 58,657.06	$ 71,118.89
	Sep-26	$ 441,974.19	$ 8,176,522.44	$ 13,391.82	$ 280,434.49	$ 7,896,087.95		$ (217,511.52)	$ 7,678,576.43	$ 13,391.82	$ 62,041.55	$ 75,433.37
	Oct-26	$ 441,974.19	$ 8,618,496.63	$ 14,135.81	$ 294,570.30	$ 8,323,926.33		$ (228,528.22)	$ 8,095,398.11	$ 14,135.81	$ 65,409.40	$ 79,545.21
	Nov-26	$ 220,987.09	$ 8,839,483.72	$ 14,693.80	$ 309,264.10	$ 8,530,219.62		$ (240,531.56)	$ 8,289,688.06	$ 14,693.80	$ 66,979.23	$ 81,673.03
	Dec-26	$ -	$ 8,839,483.72	$ 14,879.80	$ 324,143.90	$ 8,515,339.82		$ (252,483.72)	$ 8,262,856.10	$ 14,879.80	$ 66,762.43	$ 81,642.23
2027	Jan-27	$ -	$ 8,839,483.72	$ 14,879.80	$ 339,023.70	$ 8,500,460.02	$ -	$ (261,456.25)	$ 8,239,003.77	$ 14,879.80	$ 66,569.71	$ 81,449.51
	Feb-27	$ -	$ 8,839,483.72	$ 14,879.80	$ 353,903.50	$ 8,485,580.22	$ -	$ (270,428.78)	$ 8,215,151.44	$ 14,879.80	$ 66,376.98	$ 81,256.78
	Mar-27	$ -	$ 8,839,483.72	$ 14,879.80	$ 368,783.30	$ 8,470,700.42	$ -	$ (279,401.31)	$ 8,191,299.11	$ 14,879.80	$ 66,184.26	$ 81,064.06
	Apr-27	$ -	$ 8,839,483.72	$ 14,879.80	$ 383,663.10	$ 8,455,820.62	$ -	$ (288,373.84)	$ 8,167,446.78	$ 14,879.80	$ 65,991.54	$ 80,871.34
	May-27	$ -	$ 8,839,483.72	$ 14,879.80	$ 398,542.90	$ 8,440,940.82	$ -	$ (297,346.37)	$ 8,143,594.45	$ 14,879.80	$ 65,798.82	$ 80,678.62
	Jun-27	$ 220,987.09	$ 9,060,470.81	$ 15,065.80	$ 413,608.70	$ 8,646,862.11	$ 1,183.86	$ (306,593.49)	$ 8,340,268.62	$ 15,065.80	$ 67,387.91	$ 82,453.71
	Jul-27	$ 220,987.09	$ 9,281,457.90	$ 15,437.79	$ 429,046.49	$ 8,852,411.41	$ 2,565.03	$ (316,118.31)	$ 8,536,293.10	$ 15,437.79	$ 68,971.75	$ 84,409.54
	Aug-27	$ 662,961.28	$ 9,944,419.18	$ 16,181.78	$ 445,228.27	$ 9,499,190.91	$ 7,537.24	$ (326,806.63)	$ 9,172,384.28	$ 16,181.78	$ 74,111.26	$ 90,293.04
	Sep-27	$ 441,974.19	$ 10,386,393.37	$ 17,111.77	$ 462,340.04	$ 9,924,053.33	$ 11,680.75	$ (338,379.23)	$ 9,585,674.10	$ 17,111.77	$ 77,450.57	$ 94,562.34
	Oct-27	$ 441,974.19	$ 10,828,367.56	$ 17,855.76	$ 480,195.80	$ 10,348,171.76	$ 17,205.43	$ (351,267.36)	$ 9,996,904.40	$ 17,855.76	$ 80,773.23	$ 98,628.99
	Nov-27	$ 220,987.09	$ 11,049,354.65	$ 18,413.75	$ 498,609.55	$ 10,550,745.10	$ 21,348.94	$ (365,142.13)	$ 10,185,602.97	$ 18,413.75	$ 82,297.89	$ 100,711.64
	Dec-27	$ -	$ 11,049,354.65	$ 18,599.75	$ 517,209.30	$ 10,532,145.35	$ 21,348.94	$ (378,965.72)	$ 10,153,179.63	$ 18,599.75	$ 82,035.91	$ 100,635.66

2023 Total =	$ 2,209,870.93	2023 Annual Revenue Requirement =	$ 87,978.37
2024 Total =	$ 2,209,870.93	2024 Annual Revenue Requirement =	$ 344,130.44
2025 Total =	$ 2,209,870.93	2025 Annual Revenue Requirement =	$ 588,578.49
2026 Total =	$ 2,209,870.93	2026 Annual Revenue Requirement =	$ 826,112.32
2027 Total =	$ 2,209,870.93	2027 Annual Revenue Requirement =	$ 1,057,015.23

[1]per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
Resiliency Revenue Requirement Calculation
U/G Conduit

Reg Depreciation	1.43%	FERC Account 366 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	1.62%	FERC Account 366 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	*[b]*	*[c]*	*[d]*	*[e]*	*[f]*	*[g]=[d]-[f]*	*[n]*	*[o]=[g]+[n]*	*[p]=[e]*	*[q]*	*[r]=[p]+[q]*
2023	Jan-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feb-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mar-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Apr-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	May-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jun-23	$ 111.09	$ 111.09	$ 0.07	$ 0.07	$ 111.02	$ (0.15)	$ 110.87	$ 0.07	$ 0.84	$ 0.91
	Jul-23	$ 111.09	$ 222.18	$ 0.20	$ 0.27	$ 221.91	$ (0.45)	$ 221.46	$ 0.20	$ 1.68	$ 1.88
	Aug-23	$ 333.27	$ 555.45	$ 0.46	$ 0.73	$ 554.72	$ (1.37)	$ 553.35	$ 0.46	$ 4.19	$ 4.65
	Sep-23	$ 222.18	$ 777.63	$ 0.79	$ 1.52	$ 776.11	$ (2.77)	$ 773.34	$ 0.79	$ 5.86	$ 6.65
	Oct-23	$ 222.18	$ 999.81	$ 1.06	$ 2.58	$ 997.23	$ (4.86)	$ 992.37	$ 1.06	$ 7.51	$ 8.57
	Nov-23	$ 111.09	$ 1,110.90	$ 1.42	$ 4.00	$ 1,106.90	$ (7.42)	$ 1,099.48	$ 1.42	$ 8.88	$ 10.30
	Dec-23	$ -	$ 1,110.90	$ 1.50	$ 5.50	$ 1,105.40	$ (9.96)	$ 1,095.44	$ 1.50	$ 8.85	$ 10.35
2024	Jan-24	$ -	$ 1,110.90	$ 1.50	$ 7.00	$ 1,103.90	$ (11.39)	$ 1,092.51	$ 1.50	$ 8.83	$ 10.33
	Feb-24	$ -	$ 1,110.90	$ 1.50	$ 8.50	$ 1,102.40	$ (12.82)	$ 1,089.58	$ 1.50	$ 8.80	$ 10.30
	Mar-24	$ -	$ 1,110.90	$ 1.50	$ 10.00	$ 1,100.90	$ (14.25)	$ 1,086.65	$ 1.50	$ 8.78	$ 10.28
	Apr-24	$ -	$ 1,110.90	$ 1.50	$ 11.50	$ 1,099.40	$ (15.68)	$ 1,083.72	$ 1.50	$ 8.76	$ 10.26
	May-24	$ -	$ 1,110.90	$ 1.50	$ 13.00	$ 1,097.90	$ (17.11)	$ 1,080.79	$ 1.50	$ 8.73	$ 10.23
	Jun-24	$ 111.09	$ 1,221.99	$ 1.57	$ 14.57	$ 1,207.42	$ (18.68)	$ 1,188.74	$ 1.57	$ 9.60	$ 11.17
	Jul-24	$ 111.09	$ 1,333.08	$ 1.72	$ 16.29	$ 1,316.79	$ (20.40)	$ 1,296.39	$ 1.72	$ 10.47	$ 12.19
	Aug-24	$ 333.27	$ 1,666.35	$ 2.02	$ 18.31	$ 1,648.04	$ (22.73)	$ 1,625.31	$ 2.02	$ 13.13	$ 15.15
	Sep-24	$ 222.18	$ 1,888.53	$ 2.40	$ 20.71	$ 1,867.82	$ (25.52)	$ 1,842.30	$ 2.40	$ 14.89	$ 17.29
	Oct-24	$ 222.18	$ 2,110.71	$ 2.70	$ 23.41	$ 2,087.30	$ (29.00)	$ 2,058.30	$ 2.70	$ 16.63	$ 19.33
	Nov-24	$ 111.09	$ 2,221.80	$ 2.92	$ 26.33	$ 2,195.47	$ (32.99)	$ 2,162.48	$ 2.92	$ 17.47	$ 20.39
	Dec-24	$ -	$ 2,221.80	$ 3.00	$ 29.33	$ 2,192.47	$ (36.96)	$ 2,155.51	$ 3.00	$ 17.42	$ 20.42
2025	Jan-25	$ -	$ 2,221.80	$ 3.00	$ 32.33	$ 2,189.47	$ (39.67)	$ 2,149.80	$ 3.00	$ 17.37	$ 20.37
	Feb-25	$ -	$ 2,221.80	$ 3.00	$ 35.33	$ 2,186.47	$ (42.38)	$ 2,144.09	$ 3.00	$ 17.32	$ 20.32
	Mar-25	$ -	$ 2,221.80	$ 3.00	$ 38.33	$ 2,183.47	$ (45.09)	$ 2,138.38	$ 3.00	$ 17.28	$ 20.28
	Apr-25	$ -	$ 2,221.80	$ 3.00	$ 41.33	$ 2,180.47	$ (47.80)	$ 2,132.67	$ 3.00	$ 17.23	$ 20.23
	May-25	$ -	$ 2,221.80	$ 3.00	$ 44.33	$ 2,177.47	$ (50.51)	$ 2,126.96	$ 3.00	$ 17.19	$ 20.19
	Jun-25	$ 111.09	$ 2,332.89	$ 3.07	$ 47.40	$ 2,285.49	$ (53.37)	$ 2,232.12	$ 3.07	$ 18.04	$ 21.11
	Jul-25	$ 111.09	$ 2,443.98	$ 3.22	$ 50.62	$ 2,393.36	$ (56.38)	$ 2,336.98	$ 3.22	$ 18.88	$ 22.10
	Aug-25	$ 333.27	$ 2,777.25	$ 3.52	$ 54.14	$ 2,723.11	$ (59.99)	$ 2,663.12	$ 3.52	$ 21.52	$ 25.04
	Sep-25	$ 222.18	$ 2,999.43	$ 3.90	$ 58.04	$ 2,941.39	$ (64.07)	$ 2,877.32	$ 3.90	$ 23.25	$ 27.15
	Oct-25	$ 222.18	$ 3,221.61	$ 4.20	$ 62.24	$ 3,159.37	$ (68.83)	$ 3,090.54	$ 4.20	$ 24.97	$ 29.17
	Nov-25	$ 111.09	$ 3,332.70	$ 4.42	$ 66.66	$ 3,266.04	$ (74.11)	$ 3,191.93	$ 4.42	$ 25.79	$ 30.21
	Dec-25	$ -	$ 3,332.70	$ 4.50	$ 71.16	$ 3,261.54	$ (79.36)	$ 3,182.18	$ 4.50	$ 25.71	$ 30.21
2026	Jan-26	$ -	$ 3,332.70	$ 4.50	$ 75.66	$ 3,257.04	$ (83.23)	$ 3,173.81	$ 4.50	$ 25.64	$ 30.14
	Feb-26	$ -	$ 3,332.70	$ 4.50	$ 80.16	$ 3,252.54	$ (87.10)	$ 3,165.44	$ 4.50	$ 25.58	$ 30.08
	Mar-26	$ -	$ 3,332.70	$ 4.50	$ 84.66	$ 3,248.04	$ (90.97)	$ 3,157.07	$ 4.50	$ 25.51	$ 30.01
	Apr-26	$ -	$ 3,332.70	$ 4.50	$ 89.16	$ 3,243.54	$ (94.84)	$ 3,148.70	$ 4.50	$ 25.44	$ 29.94
	May-26	$ -	$ 3,332.70	$ 4.50	$ 93.66	$ 3,239.04	$ (98.71)	$ 3,140.33	$ 4.50	$ 25.37	$ 29.87
	Jun-26	$ 111.09	$ 3,443.79	$ 4.57	$ 98.23	$ 3,345.56	$ (102.73)	$ 3,242.83	$ 4.57	$ 26.20	$ 30.77
	Jul-26	$ 111.09	$ 3,554.88	$ 4.72	$ 102.95	$ 3,451.93	$ (106.90)	$ 3,345.03	$ 4.72	$ 27.03	$ 31.75
	Aug-26	$ 333.27	$ 3,888.15	$ 5.02	$ 107.97	$ 3,780.18	$ (111.67)	$ 3,668.51	$ 5.02	$ 29.64	$ 34.66
	Sep-26	$ 222.18	$ 4,110.33	$ 5.40	$ 113.37	$ 3,996.96	$ (116.91)	$ 3,880.05	$ 5.40	$ 31.35	$ 36.75
	Oct-26	$ 222.18	$ 4,332.51	$ 5.70	$ 119.07	$ 4,213.44	$ (122.83)	$ 4,090.61	$ 5.70	$ 33.05	$ 38.75
	Nov-26	$ 111.09	$ 4,443.60	$ 5.92	$ 124.99	$ 4,318.61	$ (129.27)	$ 4,189.34	$ 5.92	$ 33.85	$ 39.77
	Dec-26	$ -	$ 4,443.60	$ 6.00	$ 130.99	$ 4,312.61	$ (135.68)	$ 4,176.93	$ 6.00	$ 33.75	$ 39.75
2027	Jan-27	$ -	$ 4,443.60	$ 6.00	$ 136.99	$ 4,306.61	$ (140.60)	$ 4,166.01	$ 6.00	$ 33.66	$ 39.66
	Feb-27	$ -	$ 4,443.60	$ 6.00	$ 142.99	$ 4,300.61	$ (145.52)	$ 4,155.09	$ 6.00	$ 33.57	$ 39.57
	Mar-27	$ -	$ 4,443.60	$ 6.00	$ 148.99	$ 4,294.61	$ (150.44)	$ 4,144.17	$ 6.00	$ 33.48	$ 39.48
	Apr-27	$ -	$ 4,443.60	$ 6.00	$ 154.99	$ 4,288.61	$ (155.36)	$ 4,133.25	$ 6.00	$ 33.40	$ 39.40
	May-27	$ -	$ 4,443.60	$ 6.00	$ 160.99	$ 4,282.61	$ (160.28)	$ 4,122.33	$ 6.00	$ 33.31	$ 39.31
	Jun-27	$ 111.09	$ 4,554.69	$ 6.07	$ 167.06	$ 4,387.63	$ (165.34)	$ 4,222.29	$ 6.07	$ 34.12	$ 40.19
	Jul-27	$ 111.09	$ 4,665.78	$ 6.22	$ 173.28	$ 4,492.50	$ (170.55)	$ 4,321.95	$ 6.22	$ 34.92	$ 41.14
	Aug-27	$ 333.27	$ 4,999.05	$ 6.52	$ 179.80	$ 4,819.25	$ (176.37)	$ 4,642.88	$ 6.52	$ 37.51	$ 44.03
	Sep-27	$ 222.18	$ 5,221.23	$ 6.90	$ 186.70	$ 5,034.53	$ (182.65)	$ 4,851.88	$ 6.90	$ 39.20	$ 46.10
	Oct-27	$ 222.18	$ 5,443.41	$ 7.20	$ 193.90	$ 5,249.51	$ (189.62)	$ 5,059.89	$ 7.20	$ 40.88	$ 48.08
	Nov-27	$ 111.09	$ 5,554.50	$ 7.42	$ 201.32	$ 5,353.18	$ (197.10)	$ 5,156.08	$ 7.42	$ 41.66	$ 49.08
	Dec-27	$ -	$ 5,554.50	$ 7.50	$ 208.82	$ 5,345.68	$ (204.56)	$ 5,141.12	$ 7.50	$ 41.54	$ 49.04

2023 Total =	$ 1,110.90
2024 Total =	$ 1,110.90
2025 Total =	$ 1,110.90
2026 Total =	$ 1,110.90
2027 Total =	$ 1,110.90

2023 Annual Revenue Requirement =	$ 43.31
2024 Annual Revenue Requirement =	$ 167.34
2025 Annual Revenue Requirement =	$ 286.38
2026 Annual Revenue Requirement =	$ 402.24
2027 Annual Revenue Requirement =	$ 515.08

[1]per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
Resiliency Revenue Requirement Calculation
U/G Conduct, Dvcs

Reg Depreciation	2.69%	FERC Account 367 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	3.23%	FERC Account 367 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	[b]	[c]	[d]	[e]	[f]	[g]=[d]-[f]	[n]	[o]=[g]+[n]	[p]=[e]	[q]	[r]=[p]+[q]
2023	Jan-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feb-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mar-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Apr-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	May-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jun-23	$ 580.26	$ 580.26	$ 0.65	$ 0.65	$ 579.61	$ (0.68)	$ 578.93	$ 0.65	$ 4.38	$ 5.03
	Jul-23	$ 580.26	$ 1,160.52	$ 1.95	$ 2.60	$ 1,157.92	$ (2.00)	$ 1,155.92	$ 1.95	$ 8.75	$ 10.70
	Aug-23	$ 1,740.78	$ 2,901.30	$ 4.55	$ 7.15	$ 2,894.15	$ (6.20)	$ 2,887.95	$ 4.55	$ 21.87	$ 26.42
	Sep-23	$ 1,160.52	$ 4,061.82	$ 7.80	$ 14.95	$ 4,046.87	$ (12.50)	$ 4,034.37	$ 7.80	$ 30.55	$ 38.35
	Oct-23	$ 1,160.52	$ 5,222.34	$ 10.41	$ 25.36	$ 5,196.98	$ (22.07)	$ 5,174.91	$ 10.41	$ 39.18	$ 49.59
	Nov-23	$ 580.26	$ 5,802.60	$ 14.84	$ 40.20	$ 5,762.40	$ (33.42)	$ 5,728.98	$ 14.84	$ 46.29	$ 61.13
	Dec-23	$ -	$ 5,802.60	$ 15.62	$ 55.82	$ 5,746.78	$ (44.55)	$ 5,702.23	$ 15.62	$ 46.07	$ 61.69
2024	Jan-24	$ -	$ 5,802.60	$ 15.62	$ 71.44	$ 5,731.16	$ (49.86)	$ 5,681.30	$ 15.62	$ 45.90	$ 61.52
	Feb-24	$ -	$ 5,802.60	$ 15.62	$ 87.06	$ 5,715.54	$ (55.17)	$ 5,660.37	$ 15.62	$ 45.73	$ 61.35
	Mar-24	$ -	$ 5,802.60	$ 15.62	$ 102.68	$ 5,699.92	$ (60.48)	$ 5,639.44	$ 15.62	$ 45.57	$ 61.19
	Apr-24	$ -	$ 5,802.60	$ 15.62	$ 118.30	$ 5,684.30	$ (65.79)	$ 5,618.51	$ 15.62	$ 45.40	$ 61.02
	May-24	$ -	$ 5,802.60	$ 15.62	$ 133.92	$ 5,668.68	$ (71.10)	$ 5,597.58	$ 15.62	$ 45.23	$ 60.85
	Jun-24	$ 580.26	$ 6,382.86	$ 16.40	$ 150.32	$ 6,232.54	$ (77.05)	$ 6,155.49	$ 16.40	$ 49.74	$ 66.14
	Jul-24	$ 580.26	$ 6,963.12	$ 17.96	$ 168.28	$ 6,794.84	$ (83.57)	$ 6,711.27	$ 17.96	$ 54.23	$ 72.19
	Aug-24	$ 1,740.78	$ 8,703.90	$ 21.09	$ 189.37	$ 8,514.53	$ (92.82)	$ 8,421.71	$ 21.09	$ 68.05	$ 89.14
	Sep-24	$ 1,160.52	$ 9,864.42	$ 24.99	$ 214.36	$ 9,650.06	$ (103.99)	$ 9,546.07	$ 24.99	$ 77.13	$ 102.12
	Oct-24	$ 1,160.52	$ 11,024.94	$ 28.11	$ 242.47	$ 10,782.47	$ (118.30)	$ 10,664.17	$ 28.11	$ 86.16	$ 114.27
	Nov-24	$ 580.26	$ 11,605.20	$ 30.46	$ 272.93	$ 11,332.27	$ (134.95)	$ 11,197.32	$ 30.46	$ 90.47	$ 120.93
	Dec-24	$ -	$ 11,605.20	$ 31.24	$ 304.17	$ 11,301.03	$ (151.39)	$ 11,149.64	$ 31.24	$ 90.09	$ 121.33
2025	Jan-25	$ -	$ 11,605.20	$ 31.24	$ 335.41	$ 11,269.79	$ (161.29)	$ 11,108.50	$ 31.24	$ 89.75	$ 120.99
	Feb-25	$ -	$ 11,605.20	$ 31.24	$ 366.65	$ 11,238.55	$ (171.19)	$ 11,067.36	$ 31.24	$ 89.42	$ 120.66
	Mar-25	$ -	$ 11,605.20	$ 31.24	$ 397.89	$ 11,207.31	$ (181.09)	$ 11,026.22	$ 31.24	$ 89.09	$ 120.33
	Apr-25	$ -	$ 11,605.20	$ 31.24	$ 429.13	$ 11,176.07	$ (190.99)	$ 10,985.08	$ 31.24	$ 88.76	$ 120.00
	May-25	$ -	$ 11,605.20	$ 31.24	$ 460.37	$ 11,144.83	$ (200.89)	$ 10,943.94	$ 31.24	$ 88.43	$ 119.67
	Jun-25	$ 580.26	$ 12,185.46	$ 32.02	$ 492.39	$ 11,693.07	$ (211.43)	$ 11,481.64	$ 32.02	$ 92.77	$ 124.79
	Jul-25	$ 580.26	$ 12,765.72	$ 33.58	$ 525.97	$ 12,239.75	$ (222.54)	$ 12,017.21	$ 33.58	$ 97.10	$ 130.68
	Aug-25	$ 1,740.78	$ 14,506.50	$ 36.70	$ 562.67	$ 13,943.83	$ (236.38)	$ 13,707.45	$ 36.70	$ 110.75	$ 147.45
	Sep-25	$ 1,160.52	$ 15,667.02	$ 40.61	$ 603.28	$ 15,063.74	$ (252.14)	$ 14,811.60	$ 40.61	$ 119.68	$ 160.29
	Oct-25	$ 1,160.52	$ 16,827.54	$ 43.73	$ 647.01	$ 16,180.53	$ (271.03)	$ 15,909.50	$ 43.73	$ 128.55	$ 172.28
	Nov-25	$ 580.26	$ 17,407.80	$ 46.08	$ 693.09	$ 16,714.71	$ (292.27)	$ 16,422.44	$ 46.08	$ 132.69	$ 178.77
	Dec-25	$ -	$ 17,407.80	$ 46.86	$ 739.95	$ 16,667.85	$ (313.30)	$ 16,354.55	$ 46.86	$ 132.14	$ 179.00
2026	Jan-26	$ -	$ 17,407.80	$ 46.86	$ 786.81	$ 16,620.99	$ (327.12)	$ 16,293.87	$ 46.86	$ 131.65	$ 178.51
	Feb-26	$ -	$ 17,407.80	$ 46.86	$ 833.67	$ 16,574.13	$ (340.94)	$ 16,233.19	$ 46.86	$ 131.16	$ 178.02
	Mar-26	$ -	$ 17,407.80	$ 46.86	$ 880.53	$ 16,527.27	$ (354.76)	$ 16,172.51	$ 46.86	$ 130.67	$ 177.53
	Apr-26	$ -	$ 17,407.80	$ 46.86	$ 927.39	$ 16,480.41	$ (368.58)	$ 16,111.83	$ 46.86	$ 130.18	$ 177.04
	May-26	$ -	$ 17,407.80	$ 46.86	$ 974.25	$ 16,433.55	$ (382.40)	$ 16,051.15	$ 46.86	$ 129.69	$ 176.55
	Jun-26	$ 580.26	$ 17,988.06	$ 47.64	$ 1,021.89	$ 16,966.17	$ (396.86)	$ 16,569.31	$ 47.64	$ 133.88	$ 181.52
	Jul-26	$ 580.26	$ 18,568.32	$ 49.20	$ 1,071.09	$ 17,497.23	$ (411.89)	$ 17,085.34	$ 49.20	$ 138.05	$ 187.25
	Aug-26	$ 1,740.78	$ 20,309.10	$ 52.32	$ 1,123.41	$ 19,185.69	$ (429.65)	$ 18,756.04	$ 52.32	$ 151.55	$ 203.87
	Sep-26	$ 1,160.52	$ 21,469.62	$ 56.23	$ 1,179.64	$ 20,289.98	$ (449.33)	$ 19,840.65	$ 56.23	$ 160.31	$ 216.54
	Oct-26	$ 1,160.52	$ 22,630.14	$ 59.35	$ 1,238.99	$ 21,391.15	$ (472.14)	$ 20,919.01	$ 59.35	$ 169.02	$ 228.37
	Nov-26	$ 580.26	$ 23,210.40	$ 61.69	$ 1,300.68	$ 21,909.72	$ (497.30)	$ 21,412.42	$ 61.69	$ 173.01	$ 234.70
	Dec-26	$ -	$ 23,210.40	$ 62.47	$ 1,363.15	$ 21,847.25	$ (522.25)	$ 21,325.00	$ 62.47	$ 172.30	$ 234.77
2027	Jan-27	$ -	$ 23,210.40	$ 62.47	$ 1,425.62	$ 21,784.78	$ (539.37)	$ 21,245.41	$ 62.47	$ 171.66	$ 234.13
	Feb-27	$ -	$ 23,210.40	$ 62.47	$ 1,488.09	$ 21,722.31	$ (556.49)	$ 21,165.82	$ 62.47	$ 171.02	$ 233.49
	Mar-27	$ -	$ 23,210.40	$ 62.47	$ 1,550.56	$ 21,659.84	$ (573.61)	$ 21,086.23	$ 62.47	$ 170.37	$ 232.84
	Apr-27	$ -	$ 23,210.40	$ 62.47	$ 1,613.03	$ 21,597.37	$ (590.73)	$ 21,006.64	$ 62.47	$ 169.73	$ 232.20
	May-27	$ -	$ 23,210.40	$ 62.47	$ 1,675.50	$ 21,534.90	$ (607.85)	$ 20,927.05	$ 62.47	$ 169.09	$ 231.56
	Jun-27	$ 580.26	$ 23,790.66	$ 63.26	$ 1,738.76	$ 22,051.90	$ (625.61)	$ 21,426.29	$ 63.26	$ 173.12	$ 236.38
	Jul-27	$ 580.26	$ 24,370.92	$ 64.82	$ 1,803.58	$ 22,567.34	$ (643.94)	$ 21,923.40	$ 64.82	$ 177.14	$ 241.96
	Aug-27	$ 1,740.78	$ 26,111.70	$ 67.94	$ 1,871.52	$ 24,240.18	$ (665.01)	$ 23,575.17	$ 67.94	$ 190.48	$ 258.42
	Sep-27	$ 1,160.52	$ 27,272.22	$ 71.85	$ 1,943.37	$ 25,328.85	$ (688.00)	$ 24,640.85	$ 71.85	$ 199.09	$ 270.94
	Oct-27	$ 1,160.52	$ 28,432.74	$ 74.97	$ 2,018.34	$ 26,414.40	$ (714.12)	$ 25,700.28	$ 74.97	$ 207.65	$ 282.62
	Nov-27	$ 580.26	$ 29,013.00	$ 77.31	$ 2,095.65	$ 26,917.35	$ (742.59)	$ 26,174.76	$ 77.31	$ 211.49	$ 288.80
	Dec-27	$ -	$ 29,013.00	$ 78.09	$ 2,173.74	$ 26,839.26	$ (770.84)	$ 26,068.42	$ 78.09	$ 210.63	$ 288.72

2023 Total =	$ 5,802.60	2023 Annual Revenue Requirement =	$ 252.91
2024 Total =	$ 5,802.60	2024 Annual Revenue Requirement =	$ 992.05
2025 Total =	$ 5,802.60	2025 Annual Revenue Requirement =	$ 1,694.91
2026 Total =	$ 5,802.60	2026 Annual Revenue Requirement =	$ 2,374.67
2027 Total =	$ 5,802.60	2027 Annual Revenue Requirement =	$ 3,032.06

[1] per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
Resiliency Revenue Requirement Calculation
Line Transformers

Reg Depreciation	1.82%	FERC Account 368 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	1.83%	FERC Account 368 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	*[b]*	*[c]*	*[d]*	*[e]*	*[f]*	*[g]=[d]-[f]*	*[n]*	*[o]=[g]+[n]*	*[p]=[e]*	*[q]*	*[r]=[p]+[q]*
2023	Jan-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feb-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mar-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Apr-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	May-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jun-23	$ 18,886.27	$ 18,886.27	$ 14.32	$ 14.32	$ 18,871.95	$ (23.90)	$ 18,848.05	$ 14.32	$ 142.71	$ 157.03
	Jul-23	$ 18,886.27	$ 37,772.54	$ 42.97	$ 57.29	$ 37,715.25	$ (72.40)	$ 37,642.85	$ 42.97	$ 285.02	$ 327.99
	Aug-23	$ 56,658.81	$ 94,431.35	$ 100.25	$ 157.54	$ 94,273.81	$ (222.07)	$ 94,051.74	$ 100.25	$ 712.14	$ 812.39
	Sep-23	$ 37,772.54	$ 132,203.89	$ 171.87	$ 329.41	$ 131,874.48	$ (449.48)	$ 131,425.00	$ 171.87	$ 995.13	$ 1,167.00
	Oct-23	$ 37,772.54	$ 169,976.43	$ 229.15	$ 558.56	$ 169,417.87	$ (791.05)	$ 168,626.82	$ 229.15	$ 1,276.81	$ 1,505.96
	Nov-23	$ 18,886.27	$ 188,862.70	$ 273.61	$ 832.17	$ 188,030.53	$ (1,217.83)	$ 186,812.70	$ 273.61	$ 1,509.41	$ 1,783.02
	Dec-23	$ -	$ 188,862.70	$ 288.02	$ 1,120.19	$ 187,742.51	$ (1,640.65)	$ 186,101.86	$ 288.02	$ 1,503.67	$ 1,791.69
2024	Jan-24	$ -	$ 188,862.70	$ 288.02	$ 1,408.21	$ 187,454.49	$ (1,874.04)	$ 185,580.45	$ 288.02	$ 1,499.46	$ 1,787.48
	Feb-24	$ -	$ 188,862.70	$ 288.02	$ 1,696.23	$ 187,166.47	$ (2,107.43)	$ 185,059.04	$ 288.02	$ 1,495.24	$ 1,783.26
	Mar-24	$ -	$ 188,862.70	$ 288.02	$ 1,984.25	$ 186,878.45	$ (2,340.82)	$ 184,537.63	$ 288.02	$ 1,491.03	$ 1,779.05
	Apr-24	$ -	$ 188,862.70	$ 288.02	$ 2,272.27	$ 186,590.43	$ (2,574.21)	$ 184,016.22	$ 288.02	$ 1,486.82	$ 1,774.84
	May-24	$ -	$ 188,862.70	$ 288.02	$ 2,560.29	$ 186,302.41	$ (2,807.60)	$ 183,494.81	$ 288.02	$ 1,482.61	$ 1,770.63
	Jun-24	$ 18,886.27	$ 207,748.97	$ 302.42	$ 2,862.71	$ 204,886.26	$ (3,064.87)	$ 201,821.39	$ 302.42	$ 1,630.68	$ 1,933.10
	Jul-24	$ 18,886.27	$ 226,635.24	$ 331.22	$ 3,193.93	$ 223,441.31	$ (3,346.70)	$ 220,094.61	$ 331.22	$ 1,778.33	$ 2,109.55
	Aug-24	$ 56,658.81	$ 283,294.05	$ 388.82	$ 3,582.75	$ 279,711.30	$ (3,729.61)	$ 275,981.69	$ 388.82	$ 2,229.88	$ 2,618.70
	Sep-24	$ 37,772.54	$ 321,066.59	$ 460.82	$ 4,043.57	$ 317,023.02	$ (4,190.15)	$ 312,832.87	$ 460.82	$ 2,527.63	$ 2,988.45
	Oct-24	$ 37,772.54	$ 358,839.13	$ 518.43	$ 4,562.00	$ 354,277.13	$ (4,764.76)	$ 349,512.37	$ 518.43	$ 2,824.00	$ 3,342.43
	Nov-24	$ 18,886.27	$ 377,725.40	$ 561.63	$ 5,123.63	$ 372,601.77	$ (5,424.93)	$ 367,176.84	$ 561.63	$ 2,966.72	$ 3,528.35
	Dec-24	$ -	$ 377,725.40	$ 576.03	$ 5,699.66	$ 372,025.74	$ (6,081.14)	$ 365,944.60	$ 576.03	$ 2,956.77	$ 3,532.80
2025	Jan-25	$ -	$ 377,725.40	$ 576.03	$ 6,275.69	$ 371,449.71	$ (6,524.45)	$ 364,925.26	$ 576.03	$ 2,948.53	$ 3,524.56
	Feb-25	$ -	$ 377,725.40	$ 576.03	$ 6,851.72	$ 370,873.68	$ (6,967.76)	$ 363,905.92	$ 576.03	$ 2,940.30	$ 3,516.33
	Mar-25	$ -	$ 377,725.40	$ 576.03	$ 7,427.75	$ 370,297.65	$ (7,411.07)	$ 362,886.58	$ 576.03	$ 2,932.06	$ 3,508.09
	Apr-25	$ -	$ 377,725.40	$ 576.03	$ 8,003.78	$ 369,721.62	$ (7,854.38)	$ 361,867.24	$ 576.03	$ 2,923.82	$ 3,499.85
	May-25	$ -	$ 377,725.40	$ 576.03	$ 8,579.81	$ 369,145.59	$ (8,297.69)	$ 360,847.90	$ 576.03	$ 2,915.59	$ 3,491.62
	Jun-25	$ 18,886.27	$ 396,611.67	$ 590.43	$ 9,170.24	$ 387,441.43	$ (8,764.88)	$ 378,676.55	$ 590.43	$ 3,059.64	$ 3,650.07
	Jul-25	$ 18,886.27	$ 415,497.94	$ 619.23	$ 9,789.47	$ 405,708.47	$ (9,256.62)	$ 396,451.85	$ 619.23	$ 3,203.26	$ 3,822.49
	Aug-25	$ 56,658.81	$ 472,156.75	$ 676.84	$ 10,466.31	$ 461,690.44	$ (9,849.44)	$ 451,841.00	$ 676.84	$ 3,650.80	$ 4,327.64
	Sep-25	$ 37,772.54	$ 509,929.29	$ 748.84	$ 11,215.15	$ 498,714.14	$ (10,519.90)	$ 488,194.24	$ 748.84	$ 3,944.52	$ 4,693.36
	Oct-25	$ 37,772.54	$ 547,701.83	$ 806.44	$ 12,021.59	$ 535,680.24	$ (11,304.43)	$ 524,375.81	$ 806.44	$ 4,236.86	$ 5,043.30
	Nov-25	$ 18,886.27	$ 566,588.10	$ 849.65	$ 12,871.24	$ 553,716.86	$ (12,174.52)	$ 541,542.34	$ 849.65	$ 4,375.57	$ 5,225.22
	Dec-25	$ -	$ 566,588.10	$ 864.05	$ 13,735.29	$ 552,852.81	$ (13,040.64)	$ 539,812.17	$ 864.05	$ 4,361.59	$ 5,225.64
2026	Jan-26	$ -	$ 566,588.10	$ 864.05	$ 14,599.34	$ 551,988.76	$ (13,672.21)	$ 538,316.55	$ 864.05	$ 4,349.50	$ 5,213.55
	Feb-26	$ -	$ 566,588.10	$ 864.05	$ 15,463.39	$ 551,124.71	$ (14,303.78)	$ 536,820.93	$ 864.05	$ 4,337.42	$ 5,201.47
	Mar-26	$ -	$ 566,588.10	$ 864.05	$ 16,327.44	$ 550,260.66	$ (14,935.35)	$ 535,325.31	$ 864.05	$ 4,325.33	$ 5,189.38
	Apr-26	$ -	$ 566,588.10	$ 864.05	$ 17,191.49	$ 549,396.61	$ (15,566.92)	$ 533,829.69	$ 864.05	$ 4,313.25	$ 5,177.30
	May-26	$ -	$ 566,588.10	$ 864.05	$ 18,055.54	$ 548,532.56	$ (16,198.49)	$ 532,334.07	$ 864.05	$ 4,301.17	$ 5,165.22
	Jun-26	$ 18,886.27	$ 585,474.37	$ 878.45	$ 18,933.99	$ 566,540.38	$ (16,853.94)	$ 549,686.44	$ 878.45	$ 4,441.37	$ 5,319.82
	Jul-26	$ 18,886.27	$ 604,360.64	$ 907.25	$ 19,841.24	$ 584,519.40	$ (17,533.94)	$ 566,985.46	$ 907.25	$ 4,581.14	$ 5,488.39
	Aug-26	$ 56,658.81	$ 661,019.45	$ 964.85	$ 20,806.09	$ 640,213.36	$ (18,315.03)	$ 621,898.33	$ 964.85	$ 5,024.83	$ 5,989.68
	Sep-26	$ 37,772.54	$ 698,791.99	$ 1,036.86	$ 21,842.95	$ 676,949.04	$ (19,173.75)	$ 657,775.29	$ 1,036.86	$ 5,314.71	$ 6,351.57
	Oct-26	$ 37,772.54	$ 736,564.53	$ 1,094.46	$ 22,937.41	$ 713,627.12	$ (20,146.54)	$ 693,480.58	$ 1,094.46	$ 5,603.20	$ 6,697.66
	Nov-26	$ 18,886.27	$ 755,450.80	$ 1,137.66	$ 24,075.07	$ 731,375.73	$ (21,204.89)	$ 710,170.84	$ 1,137.66	$ 5,738.06	$ 6,875.72
	Dec-26	$ -	$ 755,450.80	$ 1,152.06	$ 25,227.13	$ 730,223.67	$ (22,259.28)	$ 707,964.39	$ 1,152.06	$ 5,720.23	$ 6,872.29
2027	Jan-27	$ -	$ 755,450.80	$ 1,152.06	$ 26,379.19	$ 729,071.61	$ (23,059.02)	$ 706,012.59	$ 1,152.06	$ 5,704.46	$ 6,856.52
	Feb-27	$ -	$ 755,450.80	$ 1,152.06	$ 27,531.25	$ 727,919.55	$ (23,858.76)	$ 704,060.79	$ 1,152.06	$ 5,688.69	$ 6,840.75
	Mar-27	$ -	$ 755,450.80	$ 1,152.06	$ 28,683.31	$ 726,767.49	$ (24,658.50)	$ 702,108.99	$ 1,152.06	$ 5,672.92	$ 6,824.98
	Apr-27	$ -	$ 755,450.80	$ 1,152.06	$ 29,835.37	$ 725,615.43	$ (25,458.24)	$ 700,157.19	$ 1,152.06	$ 5,657.15	$ 6,809.21
	May-27	$ -	$ 755,450.80	$ 1,152.06	$ 30,987.43	$ 724,463.37	$ (26,257.98)	$ 698,205.39	$ 1,152.06	$ 5,641.38	$ 6,793.44
	Jun-27	$ 18,886.27	$ 774,337.07	$ 1,166.46	$ 32,153.89	$ 742,183.18	$ (27,081.60)	$ 715,101.58	$ 1,166.46	$ 5,777.90	$ 6,944.36
	Jul-27	$ 18,886.27	$ 793,223.34	$ 1,195.26	$ 33,349.15	$ 759,874.19	$ (27,929.77)	$ 731,944.42	$ 1,195.26	$ 5,913.98	$ 7,109.24
	Aug-27	$ 56,658.81	$ 849,882.15	$ 1,252.87	$ 34,602.02	$ 815,280.13	$ (28,879.02)	$ 786,401.11	$ 1,252.87	$ 6,353.98	$ 7,606.85
	Sep-27	$ 37,772.54	$ 887,654.69	$ 1,324.87	$ 35,926.89	$ 851,727.80	$ (29,905.90)	$ 821,821.90	$ 1,324.87	$ 6,640.18	$ 7,965.05
	Oct-27	$ 37,772.54	$ 925,427.23	$ 1,382.47	$ 37,309.36	$ 888,117.87	$ (31,046.86)	$ 857,071.01	$ 1,382.47	$ 6,924.98	$ 8,307.45
	Nov-27	$ 18,886.27	$ 944,313.50	$ 1,425.68	$ 38,735.04	$ 905,578.46	$ (32,273.38)	$ 873,305.08	$ 1,425.68	$ 7,056.15	$ 8,481.83
	Dec-27	$ -	$ 944,313.50	$ 1,440.08	$ 40,175.12	$ 904,138.38	$ (33,495.93)	$ 870,642.45	$ 1,440.08	$ 7,034.64	$ 8,474.72

2023 Total =	$ 188,862.70	2023 Annual Revenue Requirement =	$ 7,545.08
2024 Total =	$ 188,862.70	2024 Annual Revenue Requirement =	$ 28,948.64
2025 Total =	$ 188,862.70	2025 Annual Revenue Requirement =	$ 49,528.17
2026 Total =	$ 188,862.70	2026 Annual Revenue Requirement =	$ 69,542.05
2027 Total =	$ 188,862.70	2027 Annual Revenue Requirement =	$ 89,014.40

[1]per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
Resiliency Revenue Requirement Calculation
Services

Reg Depreciation	1.41%	FERC Account 369 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	1.81%	FERC Account 369 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	*[b]*	*[c]*	*[d]*	*[e]*	*[f]*	*[g]=[d]-[f]*	*[n]*	*[o]=[g]+[n]*	*[p]=[e]*	*[q]*	*[r]=[p]+[q]*
2023	Jan-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feb-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mar-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Apr-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	May-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jun-23	$ 253.78	$ 253.78	$ 0.15	$ 0.15	$ 253.63	$ (0.33)	$ 253.30	$ 0.15	$ 1.92	$ 2.07
	Jul-23	$ 253.78	$ 507.56	$ 0.45	$ 0.60	$ 506.96	$ (1.02)	$ 505.94	$ 0.45	$ 3.83	$ 4.28
	Aug-23	$ 761.34	$ 1,268.90	$ 1.04	$ 1.64	$ 1,267.26	$ (3.12)	$ 1,264.14	$ 1.04	$ 9.57	$ 10.61
	Sep-23	$ 507.56	$ 1,776.46	$ 1.79	$ 3.43	$ 1,773.03	$ (6.32)	$ 1,766.71	$ 1.79	$ 13.38	$ 15.17
	Oct-23	$ 507.56	$ 2,284.02	$ 2.39	$ 5.82	$ 2,278.20	$ (11.10)	$ 2,267.10	$ 2.39	$ 17.17	$ 19.56
	Nov-23	$ 253.78	$ 2,537.80	$ 3.64	$ 9.46	$ 2,528.34	$ (16.85)	$ 2,511.49	$ 3.64	$ 20.29	$ 23.93
	Dec-23	$ -	$ 2,537.80	$ 3.83	$ 13.29	$ 2,524.51	$ (22.54)	$ 2,501.97	$ 3.83	$ 20.22	$ 24.05
2024	Jan-24	$ -	$ 2,537.80	$ 3.83	$ 17.12	$ 2,520.68	$ (25.69)	$ 2,494.99	$ 3.83	$ 20.16	$ 23.99
	Feb-24	$ -	$ 2,537.80	$ 3.83	$ 20.95	$ 2,516.85	$ (28.84)	$ 2,488.01	$ 3.83	$ 20.10	$ 23.93
	Mar-24	$ -	$ 2,537.80	$ 3.83	$ 24.78	$ 2,513.02	$ (31.99)	$ 2,481.03	$ 3.83	$ 20.05	$ 23.88
	Apr-24	$ -	$ 2,537.80	$ 3.83	$ 28.61	$ 2,509.19	$ (35.14)	$ 2,474.05	$ 3.83	$ 19.99	$ 23.82
	May-24	$ -	$ 2,537.80	$ 3.83	$ 32.44	$ 2,505.36	$ (38.29)	$ 2,467.07	$ 3.83	$ 19.93	$ 23.76
	Jun-24	$ 253.78	$ 2,791.58	$ 4.02	$ 36.46	$ 2,755.12	$ (41.76)	$ 2,713.36	$ 4.02	$ 21.92	$ 25.94
	Jul-24	$ 253.78	$ 3,045.36	$ 4.40	$ 40.86	$ 3,004.50	$ (45.56)	$ 2,958.94	$ 4.40	$ 23.91	$ 28.31
	Aug-24	$ 761.34	$ 3,806.70	$ 5.17	$ 46.03	$ 3,760.67	$ (50.72)	$ 3,709.95	$ 5.17	$ 29.98	$ 35.15
	Sep-24	$ 507.56	$ 4,314.26	$ 6.12	$ 52.15	$ 4,262.11	$ (56.93)	$ 4,205.18	$ 6.12	$ 33.98	$ 40.10
	Oct-24	$ 507.56	$ 4,821.82	$ 6.89	$ 59.04	$ 4,762.78	$ (64.67)	$ 4,698.11	$ 6.89	$ 37.96	$ 44.85
	Nov-24	$ 253.78	$ 5,075.60	$ 7.46	$ 66.50	$ 5,009.10	$ (73.57)	$ 4,935.53	$ 7.46	$ 39.88	$ 47.34
	Dec-24	$ -	$ 5,075.60	$ 7.66	$ 74.16	$ 5,001.44	$ (82.41)	$ 4,919.03	$ 7.66	$ 39.74	$ 47.40
2025	Jan-25	$ -	$ 5,075.60	$ 7.66	$ 81.82	$ 4,993.78	$ (88.39)	$ 4,905.39	$ 7.66	$ 39.63	$ 47.29
	Feb-25	$ -	$ 5,075.60	$ 7.66	$ 89.48	$ 4,986.12	$ (94.37)	$ 4,891.75	$ 7.66	$ 39.52	$ 47.18
	Mar-25	$ -	$ 5,075.60	$ 7.66	$ 97.14	$ 4,978.46	$ (100.35)	$ 4,878.11	$ 7.66	$ 39.41	$ 47.07
	Apr-25	$ -	$ 5,075.60	$ 7.66	$ 104.80	$ 4,970.80	$ (106.33)	$ 4,864.47	$ 7.66	$ 39.30	$ 46.96
	May-25	$ -	$ 5,075.60	$ 7.66	$ 112.46	$ 4,963.14	$ (112.31)	$ 4,850.83	$ 7.66	$ 39.19	$ 46.85
	Jun-25	$ 253.78	$ 5,329.38	$ 7.85	$ 120.31	$ 5,209.07	$ (118.61)	$ 5,090.46	$ 7.85	$ 41.13	$ 48.98
	Jul-25	$ 253.78	$ 5,583.16	$ 8.23	$ 128.54	$ 5,454.62	$ (125.24)	$ 5,329.38	$ 8.23	$ 43.06	$ 51.29
	Aug-25	$ 761.34	$ 6,344.50	$ 9.00	$ 137.54	$ 6,206.96	$ (133.23)	$ 6,073.73	$ 9.00	$ 49.07	$ 58.07
	Sep-25	$ 507.56	$ 6,852.06	$ 9.95	$ 147.49	$ 6,704.57	$ (142.27)	$ 6,562.30	$ 9.95	$ 53.02	$ 62.97
	Oct-25	$ 507.56	$ 7,359.62	$ 10.72	$ 158.21	$ 7,201.41	$ (152.84)	$ 7,048.57	$ 10.72	$ 56.95	$ 67.67
	Nov-25	$ 253.78	$ 7,613.40	$ 11.29	$ 169.50	$ 7,443.90	$ (164.57)	$ 7,279.33	$ 11.29	$ 58.82	$ 70.11
	Dec-25	$ -	$ 7,613.40	$ 11.48	$ 180.98	$ 7,432.42	$ (176.25)	$ 7,256.17	$ 11.48	$ 58.63	$ 70.11
2026	Jan-26	$ -	$ 7,613.40	$ 11.48	$ 192.46	$ 7,420.94	$ (184.77)	$ 7,236.17	$ 11.48	$ 58.47	$ 69.95
	Feb-26	$ -	$ 7,613.40	$ 11.48	$ 203.94	$ 7,409.46	$ (193.29)	$ 7,216.17	$ 11.48	$ 58.31	$ 69.79
	Mar-26	$ -	$ 7,613.40	$ 11.48	$ 215.42	$ 7,397.98	$ (201.81)	$ 7,196.17	$ 11.48	$ 58.14	$ 69.62
	Apr-26	$ -	$ 7,613.40	$ 11.48	$ 226.90	$ 7,386.50	$ (210.33)	$ 7,176.17	$ 11.48	$ 57.98	$ 69.46
	May-26	$ -	$ 7,613.40	$ 11.48	$ 238.38	$ 7,375.02	$ (218.85)	$ 7,156.17	$ 11.48	$ 57.82	$ 69.30
	Jun-26	$ 253.78	$ 7,867.18	$ 11.67	$ 250.05	$ 7,617.13	$ (227.69)	$ 7,389.44	$ 11.67	$ 59.71	$ 71.38
	Jul-26	$ 253.78	$ 8,120.96	$ 12.06	$ 262.11	$ 7,858.85	$ (236.86)	$ 7,621.99	$ 12.06	$ 61.58	$ 73.64
	Aug-26	$ 761.34	$ 8,882.30	$ 12.82	$ 274.93	$ 8,607.37	$ (247.40)	$ 8,359.97	$ 12.82	$ 67.55	$ 80.37
	Sep-26	$ 507.56	$ 9,389.86	$ 13.78	$ 288.71	$ 9,101.15	$ (258.98)	$ 8,842.17	$ 13.78	$ 71.44	$ 85.22
	Oct-26	$ 507.56	$ 9,897.42	$ 14.55	$ 303.26	$ 9,594.16	$ (272.09)	$ 9,322.07	$ 14.55	$ 75.32	$ 89.87
	Nov-26	$ 253.78	$ 10,151.20	$ 15.12	$ 318.38	$ 9,832.82	$ (286.36)	$ 9,546.46	$ 15.12	$ 77.13	$ 92.25
	Dec-26	$ -	$ 10,151.20	$ 15.31	$ 333.69	$ 9,817.51	$ (300.58)	$ 9,516.93	$ 15.31	$ 76.90	$ 92.21
2027	Jan-27	$ -	$ 10,151.20	$ 15.31	$ 349.00	$ 9,802.20	$ (311.37)	$ 9,490.83	$ 15.31	$ 76.68	$ 91.99
	Feb-27	$ -	$ 10,151.20	$ 15.31	$ 364.31	$ 9,786.89	$ (322.16)	$ 9,464.73	$ 15.31	$ 76.47	$ 91.78
	Mar-27	$ -	$ 10,151.20	$ 15.31	$ 379.62	$ 9,771.58	$ (332.95)	$ 9,438.63	$ 15.31	$ 76.26	$ 91.57
	Apr-27	$ -	$ 10,151.20	$ 15.31	$ 394.93	$ 9,756.27	$ (343.74)	$ 9,412.53	$ 15.31	$ 76.05	$ 91.36
	May-27	$ -	$ 10,151.20	$ 15.31	$ 410.24	$ 9,740.96	$ (354.53)	$ 9,386.43	$ 15.31	$ 75.84	$ 91.15
	Jun-27	$ 253.78	$ 10,404.98	$ 15.50	$ 425.74	$ 9,979.24	$ (365.64)	$ 9,613.60	$ 15.50	$ 77.68	$ 93.18
	Jul-27	$ 253.78	$ 10,658.76	$ 15.89	$ 441.63	$ 10,217.13	$ (377.08)	$ 9,840.05	$ 15.89	$ 79.51	$ 95.40
	Aug-27	$ 761.34	$ 11,420.10	$ 16.65	$ 458.28	$ 10,961.82	$ (389.89)	$ 10,571.93	$ 16.65	$ 85.42	$ 102.07
	Sep-27	$ 507.56	$ 11,927.66	$ 17.61	$ 475.89	$ 11,451.77	$ (403.74)	$ 11,048.03	$ 17.61	$ 89.27	$ 106.88
	Oct-27	$ 507.56	$ 12,435.22	$ 18.37	$ 494.26	$ 11,940.96	$ (419.13)	$ 11,521.83	$ 18.37	$ 93.09	$ 111.46
	Nov-27	$ 253.78	$ 12,689.00	$ 18.95	$ 513.21	$ 12,175.79	$ (435.67)	$ 11,740.12	$ 18.95	$ 94.86	$ 113.81
	Dec-27	$ -	$ 12,689.00	$ 19.14	$ 532.35	$ 12,156.65	$ (452.16)	$ 11,704.49	$ 19.14	$ 94.57	$ 113.71

2023 Total =	$ 2,537.80	2023 Annual Revenue Requirement =	$ 99.67
2024 Total =	$ 2,537.80	2024 Annual Revenue Requirement =	$ 388.47
2025 Total =	$ 2,537.80	2025 Annual Revenue Requirement =	$ 664.55
2026 Total =	$ 2,537.80	2026 Annual Revenue Requirement =	$ 933.06
2027 Total =	$ 2,537.80	2027 Annual Revenue Requirement =	$ 1,194.36

[1]per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
Resiliency Revenue Requirement Calculation
Comm Equipment

Reg Depreciation	9.06%	FERC Account 397 (Annual Rate)[1] effective November 1, 2021
Reg Depreciation	5.26%	FERC Account 397 (Annual Rate) proposed to be effective November 1, 2023
Tax Life	20	Years

Year	Month	Incremental In-Service Capital	In-Service Capital Month Ending	Regulatory Book Depreciation	Regulatory Depreciation Reserve	Net Plant	Accumulated Deferred Income Taxes	Rate Base	Return Of: *Depreciation*	Return On: *Rate Base*	Monthly Revenue Requirement
[a]	*[b]*	*[c]*	*[d]*	*[e]*	*[f]*	*[g]=[d]-[f]*	*[n]*	*[o]=[g]+[n]*	*[p]=[e]*	*[q]*	*[r]=[p]+[q]*
2023	Jan-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feb-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mar-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Apr-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	May-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jun-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jul-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Aug-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sep-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Oct-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Nov-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Dec-23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	Jan-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feb-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mar-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Apr-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	May-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jun-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jul-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Aug-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sep-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Oct-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Nov-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Dec-24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	Jan-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feb-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mar-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Apr-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	May-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jun-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jul-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Aug-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sep-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Oct-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Nov-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Dec-26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	Jan-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feb-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mar-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Apr-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	May-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jun-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Jul-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Aug-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sep-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Oct-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Nov-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Dec-27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

2023 Total =	$ -	2023 Annual Revenue Requirement =	$ -
2024 Total =	$ -	2024 Annual Revenue Requirement =	$ -
2025 Total =	$ -	2025 Annual Revenue Requirement =	$ -
2026 Total =	$ -	2026 Annual Revenue Requirement =	$ -
2027 Total =	$ -	2027 Annual Revenue Requirement =	$ -

[1] per MD PSC Order No. 89971 dated October 26, 2021 in Case No. 9490 reaffirming Public Utility Law Judge Proposed Order dated May 26, 2021

THE POTOMAC EDISON COMPANY - MARYLAND
2024 EDIS Rates
Post November 2023 Allocation

Rate Schedule	Primary NCP Allocation Factor[1]	Secondary NCP Allocation Factor[1]	Allocation Factor
	[a]	[b]	[c]= [a] x 50% + [b] x 50%
R	0.61366	0.64758	0.63062
G, C	0.13428	0.13963	0.13695
C-A, CSH	0.00395	0.00373	0.00384
PH	0.24003	0.20277	0.22140
PP	0.00213	-	0.00106
St Lighting	0.00595	0.00628	0.00612
Total	1.00000	1.00000	1.00000

Underground Cable

Rate Schedule	Allocation Factor	2024 Revenue Requirement FERC 366	FERC 367	FERC 368	Forecasted Sales kWh	Underground Cable $ / kWh
	[d]=[c]	[e]	[f]	[g]	[h]	[i] = ([e]+[f]+[g])/[h]
R	0.63062	$ 61,251.30	$ 1,039,663.31	$ 114,279.90	3,463,726,538	$ 0.00035
G, C	0.13695	$ 13,302.18	$ 225,787.63	$ 24,818.60	903,900,034	$ 0.00029
C-A, CSH	0.00384	$ 373.35	$ 6,337.14	$ 696.58	17,551,856	$ 0.00042
PH	0.22140	$ 21,504.24	$ 365,007.24	$ 40,121.63	1,891,164,520	$ 0.00023
PP	0.00106	$ 103.21	$ 1,751.91	$ 192.57	759,845,203	$ 0.00000
St Lighting	0.00612	$ 594.08	$ 10,083.80	$ 1,108.41	26,428,837	$ 0.00045
Total	1.00000	$ 97,128.36	$ 1,648,631.03	$ 181,217.69		

Recloser

Rate Schedule	Allocation Factor	2024 Revenue Requirement FERC 362	Forecasted Sales kWh	Recloser $ / kWh
	[j]=[c]	[k]	[l]=[h]	[m] = [k] / [l]
R	0.63062	$ 94,012.62	3,463,726,538	$ 0.00003
G, C	0.13695	$ 20,417.08	903,900,034	$ 0.00002
C-A, CSH	0.00384	$ 573.04	17,551,856	$ 0.00003
PH	0.22140	$ 33,006.16	1,891,164,520	$ 0.00002
PP	0.00106	$ 158.42	759,845,203	$ 0.00000
St Lighting	0.00612	$ 911.84	26,428,837	$ 0.00003
Total	1.00000	$ 149,079.16		

Resiliency

Rate Schedule	Allocation Factor	2024 Revenue Requirement FERC 362	FERC 364	FERC 365	FERC 366	FERC 367	FERC 368	FERC 369	FERC 397	Forecasted Sales kWh	Resiliency $ / kWh
	[n]=[c]	[o]	[p]	[q]	[r]	[s]	[t]	[u]	[v]	[w]=[h]	[x] = sum([o] to [v]) / [w]
R	0.63062	$ 172.00	$ 37,646.27	$ 217,016.29	$ 105.53	$ 625.61	$ 18,255.66	$ 244.98	$ -	3,463,726,538	$ 0.00008
G, C	0.13695	$ 37.36	$ 8,175.78	$ 47,130.25	$ 22.92	$ 135.87	$ 3,964.65	$ 53.20	$ -	903,900,034	$ 0.00007
C-A, CSH	0.00384	$ 1.05	$ 229.47	$ 1,322.80	$ 0.64	$ 3.81	$ 111.28	$ 1.49	$ -	17,551,856	$ 0.00010
PH	0.22140	$ 60.39	$ 13,216.93	$ 76,190.55	$ 37.05	$ 219.64	$ 6,409.23	$ 86.01	$ -	1,891,164,520	$ 0.00005
PP	0.00106	$ 0.29	$ 63.44	$ 365.69	$ 0.18	$ 1.05	$ 30.76	$ 0.41	$ -	759,845,203	$ 0.00000
St Lighting	0.00612	$ 1.67	$ 365.14	$ 2,104.86	$ 1.02	$ 6.07	$ 177.06	$ 2.38	$ -	26,428,837	$ 0.00010
Total	1.00000	$ 272.76	$ 59,697.03	$ 344,130.44	$ 167.34	$ 992.05	$ 28,948.64	$ 388.47	$ -		

Deferral Reconciliation

Rate Schedule	Allocation Factor	2023 Deferral (Over)/Under Recovery	Forecasted Sales kWh	Deferral Reconciliation $ / kWh	EDIS Total w/out GRT & Assess. Fee $ / kWh	**EDIS Total w/GRT & Assess. Fee $ / kWh**
	[y]=[c]	[z]	[aa]=[h]	[ab] = [z] / [aa]	[ac] = [i] + [m] + [x] + [ab]	***[ad] = [ac] / 0.977227***
R	0.63062	$ -	3,463,726,538	$ -	$ 0.00046	**$ 0.00047**
G, C	0.13695	$ -	903,900,034	$ -	$ 0.00038	**$ 0.00039**
C-A, CSH	0.00384	$ -	17,551,856	$ -	$ 0.00055	**$ 0.00056**
PH	0.22140	$ -	1,891,164,520	$ -	$ 0.00029	**$ 0.00030**
PP	0.00106	$ -	759,845,203	$ -	$ 0.00000	**$ 0.00000**
St Lighting	0.00612	$ -	26,428,837	$ -	$ 0.00058	**$ 0.00059**
Total	1.00000	$ -				

Underground Cable Replacement Revenue Requirement =	$ 1,926,977
Recloser Replacement Revenue Requirement =	149,079
Resiliency Revenue Requirement =	434,597
2023 Reconciliation =	-
Gross Receipt Tax & Assessment Fee =	58,507
Total =	$ 2,569,160

[1]per class cost of service sponsored by Company witness Lyons

THE POTOMAC EDISON COMPANY - MARYLAND

Authorized Rate of Return[1] / **Proposed Rate of Return**

Description	Authorized Percent	Authorized Cost Rate	Authorized Weighted Cost	Proposed Percent	Proposed Cost Rate	Proposed Weighted Cost
Long Term Debt	47.18%	4.335%	2.05%	46.47%	4.018%	1.87%
Common Equity	52.82%	9.650%	5.10%	53.53%	10.600%	5.67%
Total	100.00%		7.15%	100.00%		7.54%
Pre-Tax Rate of Return			9.09%			9.70%

Federal Income Tax Rate (FIT)	21.00%	[2]
State Income Tax Rate (SIT)	8.25%	[3]
Gross Income Tax Rate (GIT) = 1-(1-SIT)*(1-FIT)	27.52%	

[1] per PSC Order No. 89072 issued March 22, 2019 in Case No. 9490
[2] per Tax Cuts and Jobs Act of 2017, Pub. L. No. 115-97, Section 13001
[3] per COMAR 03.04.03.05

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

DONALD J. MCGETTIGAN

Concerning: Electric Distribution Reliability; EDIS Program Phases I and II

March 22, 2023

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald J. McGettigan, and my business address is 12454 Garrett Highway, Oakland, MD 21550.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by The Potomac Edison Company ("PE" or "Company") as a Director, Operations. I am one of two such directors for PE. In this capacity, I report to the President, Maryland Operations. My responsibilities include leading the PE Operations regional organization for the western half of PE's service territory. This includes responsibility for lines, substations, meter reading and the fleet organizations. The second PE operation's director is responsible for the eastern half of the service territory.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in mathematics from Frostburg State College, a Bachelor of Science degree in electrical engineering from the University of Maryland, and a Master of Business Administration degree from West Virginia University. Over the last 36 years, I have held a number of positions in both the Operations and Customer Service organizations of PE which have included Planning Engineer, Supervisor of Customer Service, Supervisor of Engineering, and General Manager of Lines/Operations. Most recently, I was appointed to the Director, Operations position in 2014. In my current role, I oversee western distribution operations of the Company, as noted above. I have also played a primary role with respect to the design and implementation of PE's current Electric Distribution Investment Surcharge ("EDIS") program.

Q. HAVE YOU TESTIFIED IN RATE PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes. Most recently, in 2018 and 2019, I provided testimony in PE's distribution base rate filing (Case No. 9490).

II. PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony is to provide supporting information regarding electric distribution operations, the Company's reliability performance for 2019 through 2022, and the EDIS program, which the Maryland Public Service Commission ("Commission") initially approved through the end of 2022[1] and then extended through 2023[2]. I will also describe the proposed incremental infrastructure improvements in the Company's electric distribution system which, if approved in this case, would form EDIS Phase II beginning in 2024, and for which the Company has proposed surcharge recovery (consistent with the current treatment of EDIS) as discussed by Company witness Fall. Finally, I address one area of state policy with respect to which, in the most recent rate cases filed by other utilities, the Commission's Staff has taken the position that the utility needs to provide

[1] See Case No. 9490.
[2] See Case No. 9490, ML#s 240413 and 240434. In the initial approval of the EDIS, the Commission stated that the Company could return prior to the sunset of the program to make a case for the extension of any of the three EDIS programs.

testimony specifically speaking to those policies. My testimony is comprised of the following sections:

- Overview of Electric Distribution Service Territory
- Distribution System Reliability
- Current and Proposed EDIS Programs
  - Underground Cable Replacement
  - Substation Recloser Replacement
  - Current Distribution Automation, Future Resiliency
- PE's labor standards and practices
- Conclusion

Q. HAVE YOU PREPARED OR HAD PREPARED UNDER YOUR SUPERVISION EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A. Yes. Exhibit DJM-1 shows the number of miles of unjacketed underground cable installed by year. Exhibit DJM-2 shows the underground cable failures from 2019 through 2022. Exhibit DJM-3 shows PE's reliability statistics, including SAIDI^{MED}[3], from 2017 through 2022.

III. OVERVIEW OF ELECTRIC DISTRIBUTION SERVICE TERRITORY

Q. PLEASE DESCRIBE THE COMPANY'S SERVICE TERRITORY.

[3] SAID^{MED} is "the SAIDI that a system experiences during major event days and can be a useful measure of that system's resilience". *Engineering Division's Review of Annual Performance Reports on Electric Service Reliability* (July 21, 2022), 72.

A. The Company provides retail electric service to approximately 285,000 customers in a service territory that covers approximately 26% of Maryland's land mass and includes all or parts of seven counties and 41 municipalities. Specifically, PE's Maryland service territory encompasses 2,547 square miles, includes all or parts of Allegany, Carroll, Frederick, Garrett, Howard, Montgomery, and Washington counties, and is served by six operating districts. PE's unique service territory is a combination of suburban, rural, and mountainous terrain and demographics, with the Company laying astride and adjacent to the eastern edge of the mountain boundary between Midwestern and Mid-Atlantic weather patterns. This means, among other things, that the Company and its customers can experience more extreme weather challenges than the rest of the state, especially in the winter months.

The Company operates and maintains over 14,200 conductor miles of primary distribution circuits, over 490 circuit miles (more than 1,470 conductor miles) of sub-transmission circuits, and in excess of 195,000 PE-owned poles. PE's electric distribution system is a three-phase, multi-grounded wye distribution system which operates at the following voltages: 4 kilovolts ("kV"), 12.47 kV, 34.5 kV, and 69 kV. The system was historically built to meet growth needs while minimizing rate impacts. The distribution system therefore is largely radial, meaning that there are many single-feed circuits with minimal opportunities to feed customers from a secondary source when they experience an outage. Also, many of the circuits traverse off-road areas and are therefore difficult to access.

Q. HAS PE'S SERVICE TERRITORY EXPERIENCED AN INCREASING NUMBER OF CUSTOMERS?

A. Yes. The number of customers served by PE has increased by approximately 1.4% per year over the last five years.

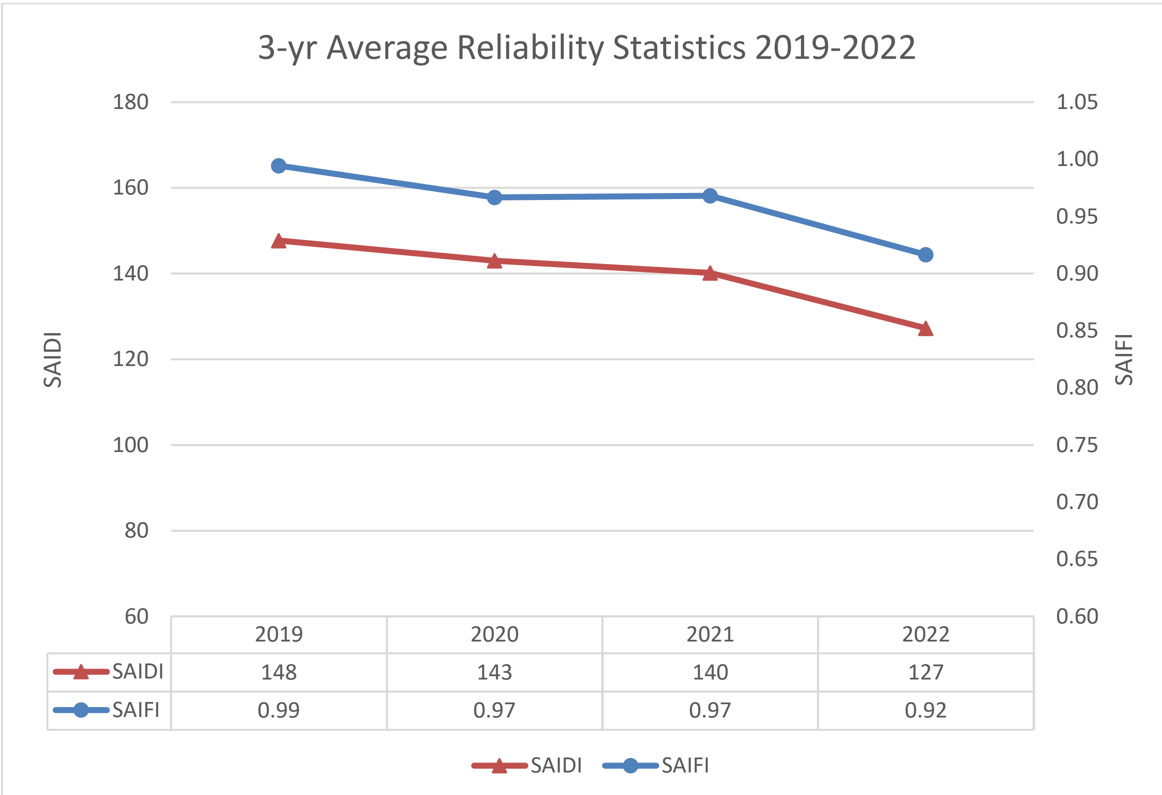
IV. DISTRIBUTION SYSTEM RELIABILITY

Q. PLEASE DISCUSS THE RELIABILITY AND PERFORMANCE OF PE'S DISTRIBUTION SYSTEM.

A. The trends in SAIFI[4] and SAIDI[5] have improved since the enactment of the Code of Maryland Regulations ("COMAR") 20.50.12 Rulemaking 43 ("RM43") in 2012. In particular, PE has seen continued improvements since 2019 with the implementation of the EDIS program. Chart 1 below reflects the three-year average reliability data for the Company for the previous four-year period.

[4]System Average Interruption Frequency Index ("SAIFI") is a measure of how often, on average, a customer experienced an interruption of service in a given year.
[5]System Average Interruption Duration Index ("SAIDI") is a measure of the number of minutes of service interruption the average customer experienced in a given year.

Chart 1: PE 3-Year Average SAIDI and SAIFI Statistics from 2019 through 2022



Q. HAS PE'S PERFORMANCE COMPLIED WITH THE MARYLAND PUBLIC SERVICE COMMISSION ("COMMISSION") REGULATORY REQUIREMENTS FOR RELIABILITY?

A. Generally, yes. Of the many requirements added to COMAR 20.50.12 in RM43, Staff highlights ten in their annual reliability reports. PE has met those highlighted standards in each of the last five years with only a relative handful of exceptions.[6] PE has met all RM43 standards for the last two years.

[6] There were two years in the previous five-year period where PE did not meet all ten COMAR standards: 2019 (SAIFI, SAIDI, and restoration within eight hours standards), and 2020 (poorest performing feeder).

Q. HAS THE COMMISSION RECENTLY REVISED THE RELIABILITY STANDARDS?

A. Yes. As required by COMAR, beginning on March 1, 2014, and every four years thereafter, each electric utility must file proposed annual SAIFI and SAIDI reliability standards for its Maryland service territory.[7] In accordance with COMAR, on March 1, 2022, PE filed its proposed reliability standards for SAIFI and SAIDI for the period 2024 through 2027. The Commission approved the proposed standards at the July 28, 2022, Administrative Hearing.

PE's SAIFI standard to be met in each of the next four years was lowered (i.e., made more stringent) to 1.05 from 1.06. PE's SAIDI standard remained flat at 142 even though the calculation using the flat reliability scenario showed that it should be 151. PE will need to continue to improve its SAIDI performance to consistently meet its SAIDI standard, especially when incorporating an appropriate planning margin.

Q. DOES PE HAVE THE DESIRE TO CONTINUE TO IMPROVE ON THESE STATISTICS?

A. Yes, and this is the main reason why the Company is proposing a Phase II to EDIS. While the three current EDIS programs that are described in my testimony were designed to have a positive impact on overall system reliability, and while customers have in fact experienced improved reliability in both blue-sky and storm conditions, the Company does see room for further improvement. The reliability impact of the current EDIS programs is

[7] COMAR 20.50.12.02.D(7).

detailed in each program description below; so are the expected future benefits of continuing the programs in EDIS Phase II along with concurrent cost recovery.

Q. IN ADDITION TO THE RELIABILITY INVESTMENTS RELATED TO THE EDIS PROGRAM, HAS THE COMPANY CONTINUED TO INVEST IN THE DISTRIBUTION SYSTEM?

A. Yes, PE has improved system reliability by investing in projects such as circuit tie additions, Supervisory Control and Data Acquisition ("SCADA") additions, and overhead to underground conversions. PE also recently installed West Jefferson Substation, a 230 kV-34.5 kV substation to eliminate source outages experienced by approximately 4,300 customers in the PE Maryland territory. Other investment types, including line reconductoring, equipment upgrades, and new substation construction, have been completed to prepare for and better serve the growing capacity needs on PE's distribution system.

V. <u>CURRENT AND PROPOSED EDIS PROGRAMS</u>

Q. WHAT PROGRAMS COMPRISE PE'S CURRENT EDIS PROGRAM?

A. PE's EDIS program is currently comprised of three programs:

(1) Underground Cable Replacement – The replacement of aging underground bare concentric neutral electrical cable that is in direct contact with the ground has been shown to improve overall system reliability and individual customer reliability. To proactively address this aging cable, PE is accelerating the replacement of bare

concentric neutral cable with more reliable, jacketed cable before failure rather than afterwards.

(2) Substation Recloser Replacements – Existing substation circuit reclosers are usually three-phase devices that operate all three phases even when a fault occurs only on a single circuit phase. Modern reclosers are designed to only interrupt the faulted circuit phase(s) in the event of a fault that does not impact all three circuit phases. With single-phase operation and electronic controller technology on modern reclosers, fewer customers experience momentary interruptions, and the number of customers experiencing sustained outages, as well as the duration of those outages, is reduced.

(3) Distribution Automation ("DA") – DA equipment and automatic restoration methods have been shown to improve overall system reliability and individual customer reliability by isolating faulted line sections and restoring service to the remainder of the feeder. DA systems employ a tie with an adjacent circuit to provide a second source during faulted conditions, therefore reducing the overall impact of an outage.

Underground Cable Replacement

Q. PLEASE DESCRIBE THE UNDERGROUND CABLE IN PE'S SERVICE TERRITORY.

A. PE began installing underground cable as early as 1938. From that time through approximately 1988, the majority of the installed underground cable was "unjacketed" with a bare concentric neutral ("BCN"). This means that the neutral conductor is in direct contact with the ground, exposing it to deterioration mechanisms, which makes it more prone to failure. This BCN cable is estimated to have an average service life of 25 to 30 years. PE estimates that it has approximately 972 miles of BCN cable. Exhibit DJM-1 shows the comparison of installed BCN cable per year in 2018 compared to 2022. The chart effectively shows the BCN cable reduction by installation year under the EDIS program.

Through the EDIS Underground Cable Replacement program, PE targets the accelerated replacement of 50 miles of direct-buried BCN underground electrical cable per year. Through December 31, 2022, approximately 206 miles of BCN cable have been replaced, leaving approximately 972 miles to be replaced. At a replacement rate of approximately 50 miles per year, the Company needs just under 20 more years to replace the remaining 972 miles of BCN cable with jacketed cable. Accordingly, PE proposes to continue the Underground Cable Replacement program in EDIS Phase II.

Q. IS PE EXPECTING AN INCREASING NUMBER OF UNDERGROUND CABLE FAILURES?

A. Yes, unless the Company continues to proactively replace the cable as it has been doing in the EDIS program. Underground cable failures typically occur on hot, sunny days and are generally lengthy to fix due to the complexity of locating the cable fault and making repairs. Since there was a higher amount of BCN cable installed during the time period of 1982 through 1988, PE expects to experience an increase in underground cable failures as additional BCN cable reaches the end of its estimated life span.

Q. DESCRIBE THE OVERALL BENEFITS OF THE REPLACEMENT OF BCN CABLE ON RELIABILITY.

A. As the BCN cable continues to age, it's estimated that the failure rate will increase dramatically. As noted above, the outages that result from an underground cable fault tend to be lengthy and inconvenient for the customer. By replacing the cable before it fails, these lengthy outages will be avoided, thereby improving both customer satisfaction and system reliability. Exhibit DJM-2 shows the decline in the number of underground cable failures since the start of the EDIS program. As more BCN cable is replaced, a greater overall benefit will continue to be realized.

<u>Substation Recloser Replacements</u>

Q. DESCRIBE PE'S CURRENT RECLOSER REPLACEMENT PROGRAM.

A. Since 2013, PE has been replacing select distribution circuit reclosers in its substations. The new reclosers employ several technological benefits over the existing substation circuit reclosers. First, the new reclosers only interrupt the faulted circuit phase(s) in the event of a fault that doesn't impact all three circuit phases. Existing substation circuit reclosers that have not yet been replaced are usually three-phase devices that operate all three phases even when a fault occurs only on a single circuit phase. Second, during momentary faults, the new reclosers analyze real-time data in order to minimize the number of customers interrupted. Third, the new reclosers have remote operation capabilities. This allows system operators in our Distribution Control Center to operate the reclosers remotely and assist line workers in the field during restoration activities.

Q. HOW MANY RECLOSERS NEED TO BE REPLACED WITH THE NEW TYPE OF SUBSTATION RECLOSERS?

A. PE's recloser program was approved to replace 68 reclosers by installing approximately 14 reclosers per year for 5 years. While PE's EDIS program was approved to begin in 2019, the recloser installations were not started until 2020 due to the lead time needed for design of the installations. There were 15 installations in 2020, 13 in 2021 and 8[8] in 2022. In 2023, 14 will be installed for a total of 50 installations over the program to date. The Company proposes that the remaining 18 installations would be completed in 2025[9] and 2026 (9 each year) in EDIS Phase II.

Q. WHAT BENEFITS HAS PE REALIZED BY INSTALLING THE NEW RECLOSERS?

A. With single-phase tripping and electronic controller technology, fewer customers experience momentary interruptions on circuits equipped with the new type of circuit recloser. In addition, the single-phase tripping feature reduces both the number of customers experiencing sustained outages as well as the duration of those outages. From 2020 through 2022, PE installed 36 reclosers which have seen an approximate benefit of 4.8 minutes of SAIDI and 0.005 SAIFI per year.

Q. ON HOW MANY ADDITIONAL CIRCUITS DOES PE PLAN TO INSTALL THE NEW RECLOSERS?

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[8] Due to supply chain issues experienced throughout 2022, materials were not available to complete the planned 14 recloser installations.

[9] Due to the lead time required for design of the recloser installations and sourcing of materials, no installations will be completed in 2024.

A. As noted above, PE plans to install the new substation reclosers on an additional 18 Maryland circuits during 2025 and 2026.

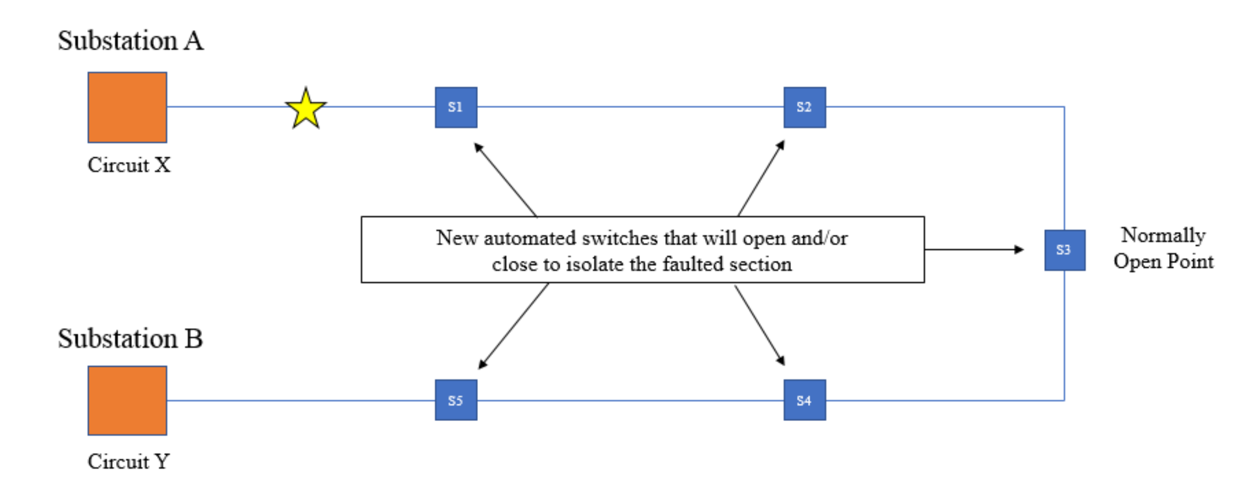
Q. WHAT OVERALL BENEFIT DOES PE ANTICIPATE FROM COMPLETION OF THE RECLOSER INSTALLATION PROGRAM?

A. PE expects to continue to see a reduction in the number of circuit lockouts as well as a reduction in the number of customers impacted when a circuit lockout does occur. This will result in an approximate 0.007 SAIFI reduction and 8.6-minute SAIDI reduction in the year following completion of the final recloser replacement (2027 and beyond).

<u>Current Distribution Automation, Future Resiliency</u>

Q. HOW DOES DA IMPROVE RELIABILITY?

A. DA systems employ a tie with an adjacent circuit to provide a second source during faulted conditions. In the diagram below, the star indicates a line fault on Circuit X between Substation A and Switch 1 ("S1"). If Circuit X had no alternate source from which it could be fed, or no way to isolate the fault, this would result in an outage of the entire circuit. However, since the fault can be isolated using S1, the rest of Circuit X can be sourced from Substation B, thereby reducing the overall impact of the outage.



Q. DESCRIBE THE OVERALL BENEFITS OF PE'S DISTRIBUTION AUTOMATION PROGRAM.

A. PE has installed 8 DA projects since the start of EDIS in 2019. These DA projects have avoided approximately 9,300 customer interruptions and 1,300,000 customer minutes interrupted that would have been experienced prior to automation. Two additional DA projects are being completed in 2023 under the current EDIS program.

Q. DOES PE DESIRE TO MAKE CHANGES TO ITS CURRENT DA PROGRAM IN EDIS PHASE II?

A. Yes. PE is proposing making the program more inclusive of other resiliency efforts. As resilience is a measure of the ability of a system to withstand unplanned service disruptions that are triggered by extraordinary events, PE is proposing resiliency enhancements to shorten outage duration during such events. While PE's SAIDI and SAIFI have shown improvement over the past four years, $SAIDI^{MED}$ has not improved over the same period (see Exhibit DJM-3). $SAIDI^{MED}$ represents the total time customers on average did not have service during major event days in a given year.

> $SAIDI^{MED}$ = SAIDI for All Interruptions – (SAIDI for All Interruptions Minus IEEE Major Event Day Interruptions).

Therefore, the lower the $SAIDI^{MED}$, the more resilient the electrical distribution system is to extraordinary events that occurred during a period of time[10].

Q. HOW WILL THE RESILIENCY PROGRAM IN EDIS PHASE II IMPROVE PE'S ABILITY TO RECOVER FROM OUTAGE EVENTS?

A. Enhancements to resiliency will improve the ability of PE's distribution and sub-transmission system to return customers to service after outage events. These enhancements will involve circuit ties, circuit splits, line relocation, distribution automation, and upgraded circuit protection as necessary to enhance resiliency.

Q. HAS PE COMPLETED RESILIENCY PROJECTS IN THE PAST?

A. Yes. PE's DA projects, which are part of the currently approved EDIS Program, have contributed to resiliency by enabling the automatic restoration of service to blocks of customers in the event of a fault.

Q. HOW DOES THE PROPOSED RESILIENCY PROGRAM DIFFER FROM DA?

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[10] *Engineering Division's Review of Annual Performance Reports on Electric Service Reliability* (July 21, 2022), 72.

A. The DA projects focused on one solution to restoring customers after an outage event. As described above, the resiliency program would allow for the implementation of additional solutions to restoration and resiliency.

Q. WHAT IMPROVEMENTS DOES PE EXPECT FROM A RESILIENCY PROGRAM?

A. PE expects enhancements to resiliency to shorten the duration of customer outages. These enhancements are expected to save approximately 3.4 minutes SAIDI and 0.008 SAIFI per year.

Q. DESCRIBE THE RESILIENCY PROGRAM PROJECTS PLANNED FOR EDIS PHASE II DURING 2024 AND THEIR PROJECTED BENEFITS.

A. PE is planning two resiliency projects for 2024. The first involves the installation of automated switches and remotely controlled switches to remotely sectionalize portions of the sub-transmission lines feeding PE's Wilson Substation in Washington County. This project is expected to save 2.1 minutes of SAIDI and 0.007 SAIFI per year. The second involves the installation of the circuit tie line between the Hoyes – Accident and the Jennings – Grantsville circuits in Garrett County. This tie line will be five miles long. The project also involves installation of a DA system that will allow for automatic restoration to portions of the circuit in the event of a fault. This project is expected to save 1.3 minutes of SAIDI and 0.001 SAIFI per year.

Q. HOW WILL PE PROPOSE AND RECEIVE APPROVAL FOR FUTURE PROJECTS UNDER THE RESILIENCY PROGRAM?

A. Beginning in October 2024, and each October throughout EDIS Phase II, PE will submit for review and approval the following year's resiliency projects. For example, PE will propose 2025 resiliency projects in October 2024.

Q. CAN YOU SUMMARIZE HOW THE PROGRAMS DISCUSSED IN YOUR TESTIMONY ABOVE PROVIDE BENEFITS FOR PE'S CUSTOMERS?

A. Yes. The current EDIS programs discussed above provided additional and incremental investments in the distribution grid to help support a safe, efficient, and reliable electric system and, importantly, a safe, efficient, and reliable experience for our customers. From my operating perspective, the three new or continuing programs in EDIS Phase II build on that foundation and would further improve on the Company's diligent efforts to meet and exceed our customers' expectations for increasingly reliable service at affordable rates.

Q. WHY DOES PE BELIEVE THAT THE THREE PROGRAMS IN EDIS PHASE II WOULD BE APPROPRIATE FOR SURCHARGE TREATMENT?

A. These are additional stretch programs, similar to the types of programs for which PE has received surcharge recovery in its existing EDIS. Also, the annual review and surcharge approach approved by the Commission in PE's last distribution base rate case allows for close and timely scrutiny of the plans for each year. It also allows for costs to be trued up each year, as discussed by Company witness Fall. The forecasted capital costs associated with EDIS Phase II and determination of the associated revenue requirement are provided in the direct testimony of Company witness Fall.

VI. PE'S LABOR STANDARDS AND PRACTICES

Q. DOES PE MAINTAIN FAIR AND STABLE LABOR STANDARDS?

A. Yes. PE's labor force is made up of both unionized and non-unionized employees. Most of the Company's Maryland employees are covered under a collective bargaining agreement that historically has been renegotiated every five years. The Company maintains a collaborative relationship with Utility Workers Union of America ("UWUA") Local 102 by communicating regularly with union leadership and working together to promptly address any issues that arise. It is my understanding that PE is in compliance and ensures its compliance with all applicable federal, state, and local labor laws by promulgating a Code of Business Conduct and enforcing Company rules and policies that are compliant with laws and protect employees in the workplace.

Q. CAN YOU BE MORE SPECIFIC WITH REGARD TO LABOR STANDARDS WITH WHICH PE COMPLIES?

A: Yes. I am aware that PE complies with numerous federal and state rules relating to labor standards. Specifically, I have seen notices that the Company posts which explain that PE complies with the:

- Employee Polygraph Protection Act
- Occupational Safety and Health Act of 1970
- Equal Employment Opportunity
- Uniformed Services Employment and Reemployment Rights Act
- Fair Labor Standards Act

- Family and Medical Leave Act of 1993
- National Labor Relations Act
- Pay Transparency Nondiscrimination rules
- Rules relating to workers with disabilities
- Paid Sick Leave rules
- Walsh-Healey Public Contracts/Service Contracts rules
- Federal rules about reporting fraud and misconduct
- Federal Right to Work rules
- Davis Bacon Act

Q. IN ADDITION TO THESE FEDERAL RULES, ARE YOU AWARE OF ANY STATE LABOR RULES WITH WHICH PE COMPLIES?

A. Yes. I have seen notices indicating that PE complies with Maryland laws and rules relating to:

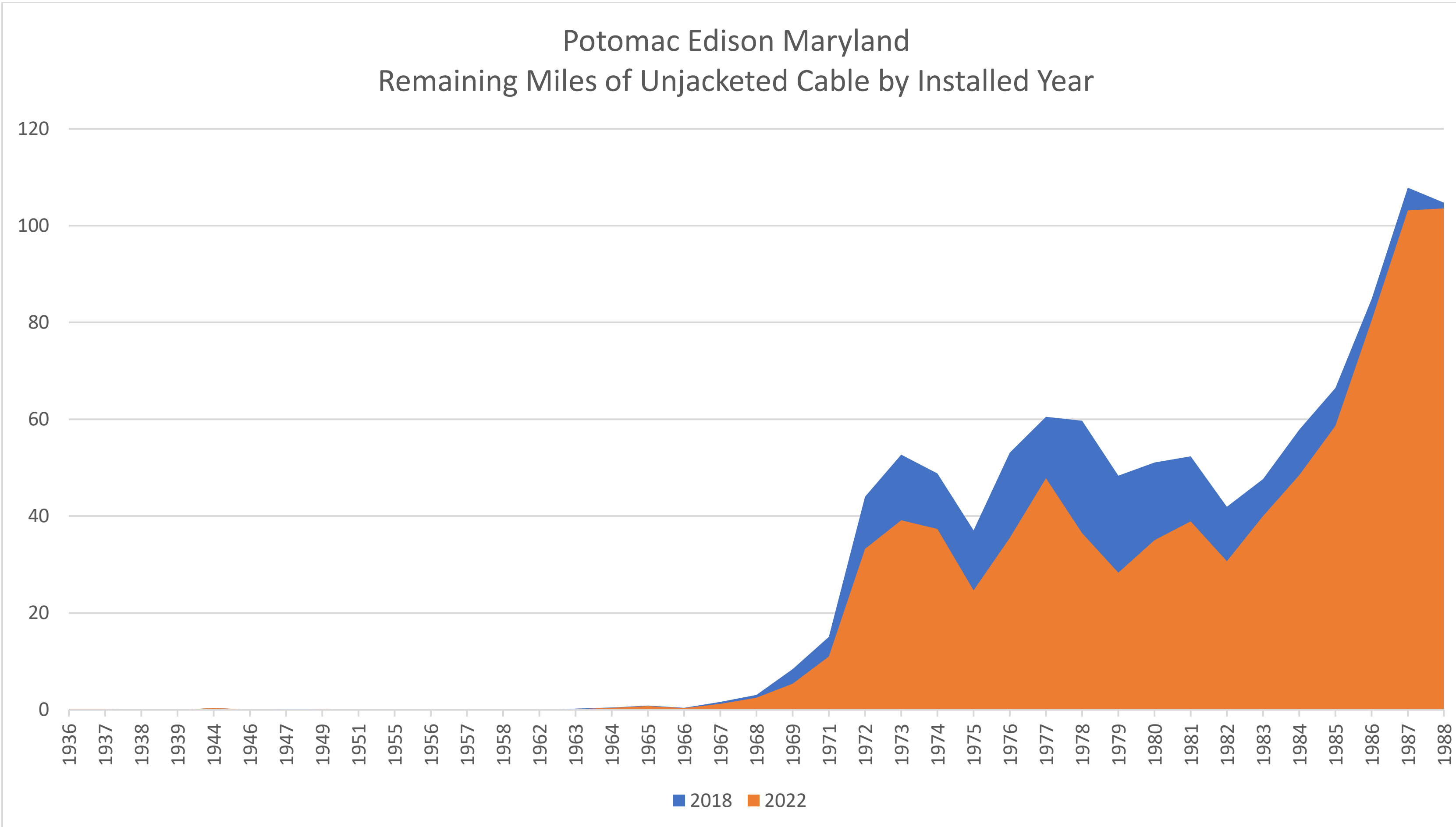
- Child Labor
- Pregnancy while working
- Earned Sick and Safe Leave
- Health Insurance
- Equal Pay for Equal Work
- Minimum Wage
- Unemployment Insurance
- Fair Employment

- Worker's Compensation
- State Occupational Safety and Health Administration requirements
- No smoking

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.


Potomac Edison Maryland
Remaining Miles of Unjacketed Cable by Installed Year
120
100
80
60
40
20
0
1936
1937
1938
1939
1944
1946
1947
1949
1951
1955
1956
1957
1958
1962
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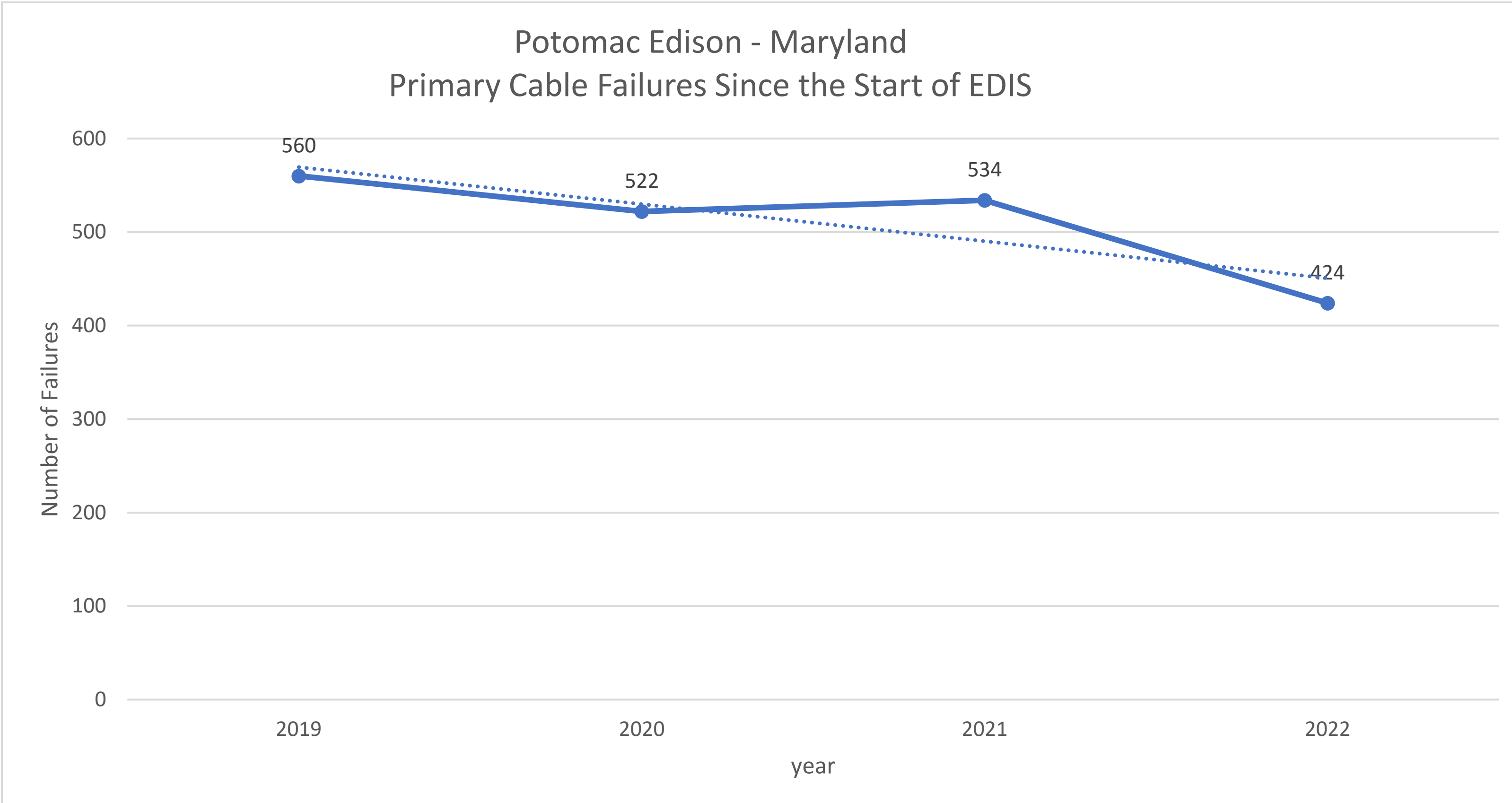
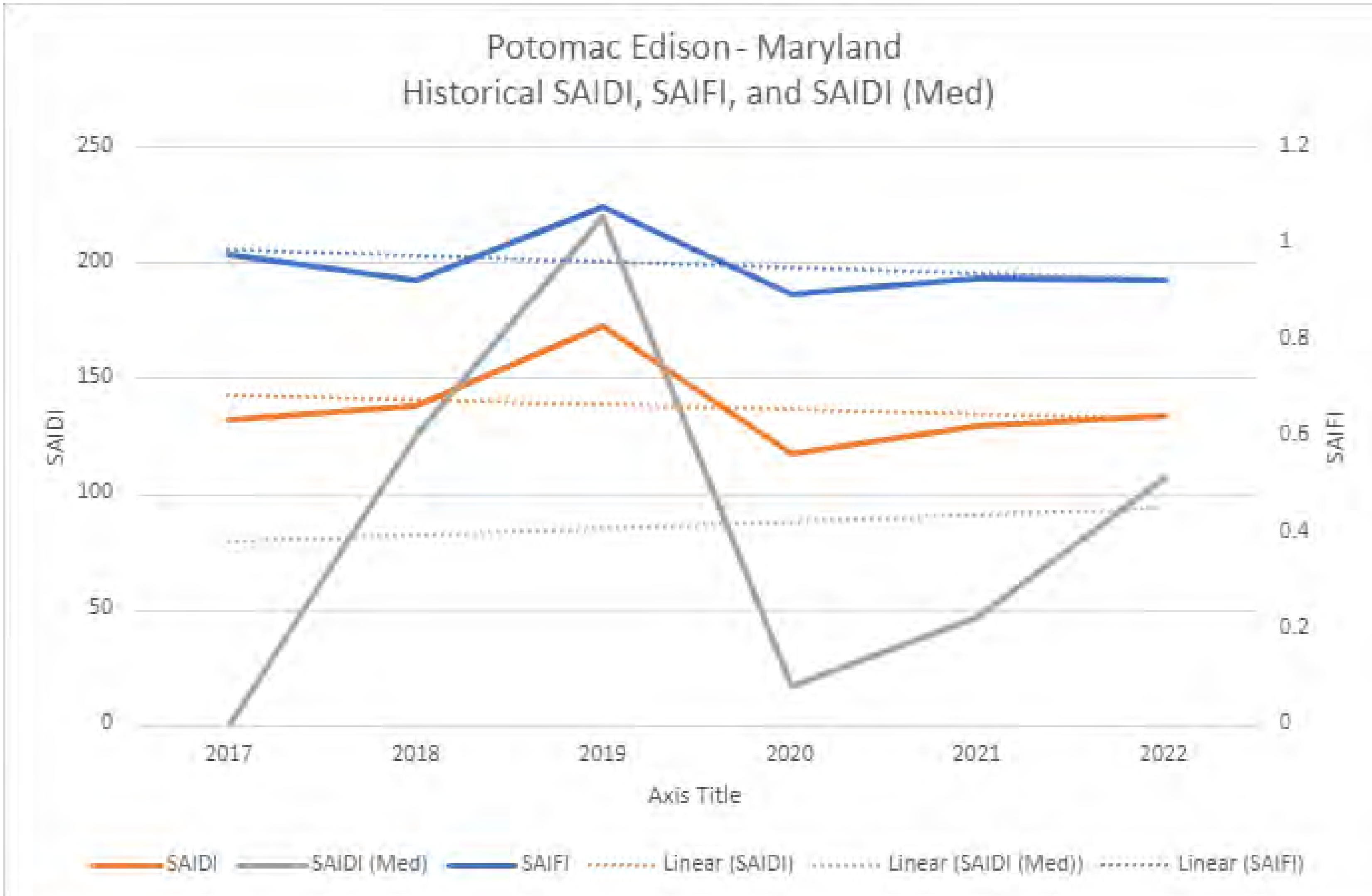
1988
2018
2022


Potomac Edison - Maryland
Primary Cable Failures Since the Start of EDIS
Number of Failures
600
500
400
300
200
100
0
560
522
534
424
2019
2020
2021
2022
year


Potomac Edison - Maryland
Historical SAIDI, SAIFI, and SAIDI (Med)
250
200
150
100
50
0
1.2
1
0.8
0.6
0.4
0.2
0
SAIDI
SAIFI
2017
2018
2019
2020
2021
2022
Axis Title
SAIDI
SAIDI (Med)
SAIFI
Linear (SAIDI)
Linear (SAIDI (Med))
Linear (SAIFI)

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

WEIZHONG (BILL) WANG

March 22, 2023

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Weizhong (Bill) Wang. My business address is 76 South Main Street, Akron, Ohio 44308.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by FirstEnergy Service Company as Assistant Treasurer, Treasury.

Q. WHAT ARE YOUR RESPONSIBILITIES?

A. I previously managed capital structures for FirstEnergy Corp. ("FE") and its subsidiaries, including The Potomac Edison Company ("PE" or "Company"). Currently, I am responsible for managing $12 billion in investments related to the FE pension plan, FE Foundation, FE Savings Plans and various other post-retirement plans. I am also responsible for pension-related budgeting, forecasting and financial planning in various states including Maryland.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I joined Corning Incorporated as a Senior Financial Analyst in May 2001 after I received a Master of Business Administration from the Business School of the University of Maryland in College Park. At Corning, I was part of the Treasury team and participated in its capital structure management, including various capital market transactions and banking relationship management. In July 2005, I joined Allegheny Energy, which then merged with FE in 2011. I was elected to the Assistant Treasurer role in 2016. Prior to that, I served in various Treasury positions, such as Director, Treasury Integration and Director, Investment Management, managing FE's capital structure, $12 billion asset investments related to FE's Pension Plan, Savings Plan and other post-retirements plans. I have also served as the Treasurer of Jersey Central Power & Light Company ("JCP&L") since 2012.

Q. HAVE YOU TESTIFIED IN RATE PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes. I have provided direct testimony in the 2023 distribution base rate case proceeding before the New Jersey Board of Public Utilities on behalf of JCP&L.

II. PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. I am testifying on behalf of the Company to describe and support: (1) PE's capital structure; (2) PE's embedded cost of long-term debt; and (3) PE's overall weighted average cost of capital.

Q. HAVE YOU PREPARED OR HAD PREPARED UNDER YOUR SUPERVISION EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibits for the Company, which will be discussed further in this testimony:

Exhibit BW-1: Capital Structure

Exhibit BW-2: Embedded Cost of Long-Term Debt

Exhibit BW-3: Overall Weighted Average Cost of Capital

III. CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE RATIOS ARE THE COMPANY PROPOSING TO BE UTILIZED FOR PURPOSES OF DETERMINING THE COMPANY'S OVERALL WEIGHTED AVERAGE COST OF CAPITAL?

A. The Company is proposing to utilize its actual capital structure. As indicated in Exhibit BW-1, PE's actual capital structure on December 31, 2022 has capital structure ratios of 53.53% for common equity and 46.47% for long-term debt.

Q. DOES THE COMPANY HAVE PREFERRED STOCK OR SHORT-TERM DEBT?

A. The Company does not have preferred stock but did have $15 million of short-term debt as of December 31, 2022.

Q. IS SHORT-TERM DEBT INCLUDED IN THE CAPITAL STRUCTURE RATIOS?

A. No, short-term debt is not included in the capital structure ratios since such borrowings are typically short-term sources of working capital to bridge operational cash needs, are less than 12 months in length, and do not represent components of long-term capital required to support the rate base of the Company. Since short-term debt does not typically finance long-term assets, it would be improper to include such debt in the Company's capital structure for determination of the rate of return on long-term assets. The Company's capital structure for ratemaking purposes reflects the financing of long-term assets, which explains the absence of short-term debt from BW-1.

Q. WHY IS THE COMPANY'S PROPOSED CAPITAL STRUCTURE APPROPRIATE?

A. The 53.53% equity ratio supports PE's goals of maintaining solid investment-grade ratings and having access to capital on reasonable terms. In addition, the Company's capital structure is consistent with capital structure accepted by the Maryland Public Service Commission in other rate proceedings.[1]

IV. COST OF CAPITAL

Q. WHAT EMBEDDED COST OF LONG-TERM DEBT IS THE COMPANY PROPOSING TO BE UTILIZED FOR PURPOSES OF DETERMINING THE COMPANY'S OVERALL WEIGHTED AVERAGE COST OF CAPITAL?

A. As indicated in Exhibit BW-2, the Company's embedded long-term debt cost rate is 4.018%.

Q. HOW DID YOU DETERMINE THE EMBEDDED LONG-TERM DEBT COST RATE?

A. The determination of a utility's embedded long-term debt cost rate is essentially an arithmetic exercise due to the fact that the utility has contracted for the use of the capital in question for a defined period of time at a specified cost rate. The calculations, which take into account debt issuance and reacquisition expenses, are provided in Exhibit BW-2.

Q. PLEASE DESCRIBE WHAT IS SHOWN ON EXHIBIT BW-2.

A. Exhibit BW-2 itemizes each series of debt, the date of issuance, maturity, original amount issued and amount outstanding as of December 31, 2022. The Premium/Discount and Issuance Expenses column represents legal, underwriting and other miscellaneous costs

[1] The capital structure approved by the Commission in the Company's prior distribution rate case (Case No. 9490) was 52.82% equity, 47.18% long-term debt, and no short-term debt.

associated with each issuance. The principal amount issued, adjusted for any premium or discount, less any issuance expenses, equals the Net Proceeds. The effective rate is calculated by incorporating the Net Proceeds at the time of issuance in relation to the interest rate and the years to maturity. After the effective rate is calculated for each individual series, the rates are multiplied by each respective net amount outstanding to determine the annual net cost. Next, the unamortized balance and annual cost of debt reacquisition costs are included. Finally, the embedded cost rate is determined by dividing the total annual net cost by the total net amount outstanding.

Q. WHAT OVERALL WEIGHTED AVERAGE COST OF CAPITAL IS THE COMPANY PROPOSING TO BE UTILIZED?

A. As indicated in Exhibit BW-3, the Company is proposing to utilize an Overall Weighted Cost of Capital of 7.54%.

Q. HOW DID YOU CALCULATE THE OVERALL WEIGHTED COST OF CAPITAL?

A. As set forth in Exhibit BW-3, I quantified, and then combined, the Company's weighted average cost of long-term debt and common equity by multiplying the actual December 31, 2022 capitalization ratios presented in Exhibit BW-1 by: (1) the embedded cost of long-term debt developed on Exhibit BW-2 of 4.018%; and (2) the Company's requested return on common equity of 10.6%. The proposed cost of equity is supported by Company witness D'Ascendis.

Q. DO YOU HAVE ANY OTHER COMMENTS WITH REGARD TO YOUR TESTIMONY?

A. Yes. I believe that it is vital that the Company maintains access to the capital markets on reasonable terms. Setting a rate of return which is based on a capital structure that warrants solid investment grade ratings is necessary because it allows the Company to access the capital markets on favorable terms, to maintain its financial integrity and financial flexibility, and fund investments in its distribution system that are necessary for safe, proper, and adequate service. Customers, in turn, benefit from the Company incurring lower debt costs as a result.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

The Potomac Edison Company
Capital Structure
Actual at December 31, 2022

Type of Capital	Actual December 31, 2022 Amount ($)	Ratios
Long-term Debt	$ 675,000,000	
Unamortized Net Discount	-	
Unamortized Debt Issuance Expense	(3,712,122)	
Unamortized Debt Reacquisition Costs	(542)	
Total Long-term Debt	$ 671,287,336	46.47%
Common Equity	$ 773,299,730	53.53%
Total	$ 1,444,587,066	100.00%

The Potomac Edison Company
Embedded Cost of Long-term Debt
Actual at December 31, 2022

Type of Issue	Coupon Rate (a)	Date Issued (b)	Maturity Date (c)	Principal Amount Issued (d)	Unamortized (Premium)/ Discount (f)	Unamortized Debt Issuance Expense (g)	Net Amount Outstanding (e)	Effective Cost Rate (i)	Annual Net Cost (h)
First Mortgage Bonds	4.440%	11/25/2014	11/15/2044	$ 200,000,000	$ -	$ 921,323	$ 199,078,677	4.478%	$ 8,915,473
	4.470%	8/17/2015	8/15/2045	$ 145,000,000	$ -	$ 823,857	$ 144,176,143	4.516%	$ 6,511,091
	3.890%	10/17/2016	10/15/2046	$ 155,000,000	$ -	$ 884,054	$ 154,115,946	3.931%	$ 6,058,280
	2.670%	6/29/2020	6/15/2032	$ 75,000,000	$ -	$ 453,244	$ 74,546,756	2.744%	$ 2,045,534
	3.430%	6/29/2020	6/15/2051	$ 100,000,000	$ -	$ 629,644	$ 99,370,356	3.466%	$ 3,444,151
Total First Mortgage Bonds				$ 675,000,000	$ -	$ 3,712,122	$ 671,287,878		$ 26,974,529
Unamortized Debt Reacquisition Costs							$ (542)		$ 542
Total Long-term Debt Balance				$ 675,000,000	$ -	$ 3,712,122	$ 671,287,336	4.018%	$ 26,975,071

Type of Issue	Coupon Rate	Date Issued	Maturity Date	Original Principal Amount Issued	Original (Premium)/ Discount	Original Debt Issuance Expense	Original Net Proceeds to Company	Net Amount Per Unit	Effective Cost Rate
First Mortgage Bonds	4.440%	11/25/2014	11/15/2044	$ 200,000,000	$ -	$ 1,261,677	$ 198,738,323	$ 99.37	4.478%
	4.470%	8/17/2015	8/15/2045	$ 145,000,000	$ -	$ 1,091,999	$ 143,908,001	$ 99.25	4.516%
	3.890%	10/17/2016	10/15/2046	$ 155,000,000	$ -	$ 1,113,718	$ 153,886,282	$ 99.28	3.931%
	2.670%	6/29/2020	6/15/2032	$ 75,000,000	$ -	$ 562,840	$ 74,437,160	$ 99.25	2.744%
	3.430%	6/29/2020	6/15/2051	$ 100,000,000	$ -	$ 680,788	$ 99,319,212	$ 99.32	3.466%
Total First Mortgage Bonds				$ 675,000,000	$ -	$ 4,711,022	$ 670,288,978		

The Potomac Edison Company
Weighted Average Cost of Capital
Actual at December 31, 2022

Type of Capital	Actual December 31, 2022 Amount ($)	Ratios	Cost Rate	Weighted Cost
Long-term Debt	$ 675,000,000			
Unamortized Net Discount	-			
Unamortized Debt Issuance Expense	(3,712,122)			
Unamortized Debt Reacquisition Costs	(542)			
Total Long-term Debt	$ 671,287,336	46.47%	4.018%	1.87%
Common Equity	$ 773,299,730	53.53%	10.600%	5.67%
Total	$ 1,444,587,066	100.00%		7.54%

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

GREGORY J. GAWLIK

Concerning: Federal and State Income Tax; Significant Tax Law Changes

March 22, 2023

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gregory J. Gawlik, and my business address is 76 South Main Street, Akron, Ohio, 44308.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by FirstEnergy Service Company and my title is Assistant Controller, Tax, serving as head of the tax department. My responsibilities include federal and state tax compliance and audits, tax planning and business unit support, and financial reporting for taxes.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Bowling Green State University in 1997 with a Bachelor of Arts degree. I received a Juris Doctorate from Cleveland State University College of Law in 2000. After graduating law school, I practiced law with the firm Thompson Hine LLP in Cleveland, Ohio, focusing on federal and state tax planning and litigation, making partner in November 2008. I left Thompson Hine in January 2011 and became employed with FirstEnergy in February 2011 as Director, Tax Planning. I assumed my current role, Assistant Controller, Tax, in September 2018.

II. PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. My testimony supports the state and federal income tax information used by The Potomac Edison Company ("PE" or "Company") in this rate case, and I also discuss significant tax law changes affecting the Company.

Q. PLEASE IDENTIFY THE LOCATION OF THE STATE AND FEDERAL INCOME TAX INFORMATION IN THE COMPANY'S FILING.

A. Exhibit No. JAS-1 from Company witness Soltis contains an income statement summary that includes state and federal income tax, as well as deferred income tax, for the test year ended December 31, 2022. With regard to rate base, accumulated deferred income taxes ("ADIT") are identified as the Deferred Federal and State Tax Balance and represents the average balance during 2022. This exhibit starts out with the Company's total taxes per books and then allocates a portion to Maryland jurisdictional operations. To these amounts, the tax effect of going-level adjustments and pro forma adjustments have been applied to reflect the final Maryland jurisdictional amounts. The allocation to Maryland, as well as the associated going-level and pro forma adjustments, are addressed by Company witnesses Soltis and Colflesh.

III. DEFERRED TAXES

Q. WHAT ARE DEFERRED INCOME TAXES AND HOW DO THEY OCCUR?

A. Deferred income taxes arise when income tax amounts calculated for book purposes differ from the amount of taxes reported on a tax return and due to be paid in a particular year. The primary cause of the tax differences is that straight-line depreciation rates are traditionally used for ratemaking purposes whereas accelerated depreciation rates are used for income tax purposes.[1] In the early years of an asset's life, there is typically higher depreciation expense for tax purposes than for regulatory book purposes, causing the taxes computed for regulatory books to be greater than taxes computed for tax return purposes. This results in a buildup of ADIT during this period, which is a reduction to utility rate base. In the later years of an asset's life, the situation reverses, resulting in taxes computed for regulatory books that are less than the taxes computed for tax return purposes. During this period, the ADIT balance for the asset in question is progressively reduced as the utility makes tax payments that reflect the progressive reversal of the difference between book and tax depreciation over time, with a corresponding progressive reduction in the ADIT balance/rate base offset associated with that asset.

Since revenues and expenses for tax purposes can be recognized earlier or later than when they are accounted for on a regulatory book basis, normalization (or smoothing of the rate effect) is an inter-period tax allocation based on the premise that taxes recorded on the income statement for an accounting period should match the revenues and expenses recorded on a regulatory book basis for the same period.

Q. DOES THE COMPANY NORMALIZE BOTH STATE AND FEDERAL INCOME TAX?

A. Yes. The Company normalizes state income taxes along with federal income taxes, which helps to mitigate annual fluctuations in rates that could result from a flow-through of state income tax expense in lieu of normalization. The Company's normalization of income

[1] Deferred income taxes also arise from other (non-depreciation) book-tax timing differences for items of income and expense.

taxes helps to ensure that the treatment of such taxes is consistent on both a state and federal basis.

Q. WILL THE COMPANY CONTINUE TO FLOW THROUGH TO CUSTOMERS THE BENEFITS OF THE REDUCTION IN FEDERAL TAXES ENACTED IN THE TAX CUTS AND JOBS ACT OF 2017 ("TCJA")?

A. Yes. The Company will continue to flow through to customers the benefits of the reduction in federal taxes enacted in the TCJA and intends to do so in compliance with the normalization provisions of the Internal Revenue Code (the "Code"). To maintain compliance with the normalization provisions of the Code, the Company refined its accounting process for amortizing property-related excess ADIT. However, as explained further, the change does not impact the timing of refunds of property-related excess ADIT to customers.

Q. PLEASE EXPLAIN THE REFINEMENT TO EXCESS ADIT AMORTIZATION.

A. As agreed in the Company's prior distribution rate case, concluded in March 2019, the Company is using the average rate assumption method ("ARAM")[2] to amortize property-related excess ADIT attributable to both book-tax depreciation timing differences and non-depreciation timing differences over the remaining regulatory life of the assets. In 2021

[2] The ARAM determines how quickly excess ADIT related to the difference between accelerated tax depreciation and book depreciation can be refunded in compliance with the normalization provisions of the Code. Section 13001(d)(3)(B) of the TCJA defines the ARAM as the method under which the excess in the reserve for deferred taxes is reduced over the remaining lives of the property as used in the regulated books of account which gave rise to the reserve for deferred taxes. Under such a method, during the time period in which the timing differences for the property reverse, the amount of the adjustment to the reserve for the deferred taxes is calculated by multiplying the ratio of the aggregate deferred taxes for the property to the aggregate timing differences for the property as of the beginning of the period in question, by the amount of the timing differences which reverse during such period.

and 2022, the Internal Revenue Service ("IRS") issued certain private letter rulings ("PLRs")[3] to other regulated utilities in which it concluded that including cost-of-removal ("COR") accrual as a component of book depreciation expense for purposes of the ARAM is not consistent with a normalization method of accounting. In general, including the COR accrual in book depreciation can cause book-tax depreciation timing differences to reverse faster and, therefore, the depreciation-related excess ADIT to be refunded faster, than allowed under normalization principles.[4] The Company's fixed asset software had the COR accrual built into book depreciation but the timing impact on ARAM amortization was mostly offset by the fact that actual COR experience was being allocated to deductible tax retirements. Nevertheless, in response to the PLRs, the Company reconfigured its fixed asset software to separate the COR accrual from book depreciation expense and separate actual COR experience from tax retirements. Separating the COR accrual from book depreciation expense created a COR-specific timing difference (in this case an asset) that builds or reverses independently of book-tax depreciation timing differences.[5] The system configuration changes did not change the total amount of property-related excess ADIT to be refunded to customers, but only shifted amounts between depreciation and non-depreciation-related categories, all of which will continue to be amortized over the

[3] PLRs 202141001 (October 2021), 202211004 (March 2022), and 202230005 (July 2022). A PLR is only binding on the taxpayer to whom it is issued. Therefore, the PLRs are not binding on the Company. However, any PLR provides insight into the IRS's legal position on issues and similarly situated taxpayers should expect that the IRS would apply the law in like kind to their situation.

[4] In essence, the IRS explained that COR is deductible under the Code independent of accelerated depreciation and, therefore, it reverses through the actual incurred COR expenditures, not through book-tax depreciation timing differences.

[5] The configuration changes were made with respect to excess and deficient ADIT balances as of January 1, 2021.

remaining regulatory life of the assets using the ARAM as before.[6] The COR-specific ADIT asset also will build or reverse over the remaining regulatory life of the assets. The Company is informing the Maryland Public Service Commission of the COR configuration changes to maintain compliance with the normalization provisions of the Code. Also, in compliance with the normalization rules, the Company's rate base reflects a reduction in the TCJA-related regulatory liability for the actual amount of excess and deficient ADITs amortized and refunded to customers through December 31, 2022, and the ARAM amortization amount included as a reduction to cost of service will reflect actual ARAM amortization during the period January 1, 2022, to December 31, 2022.

IV. TAX LAW CHANGES

Q. HAVE THERE BEEN ANY SIGNIFICANT FEDERAL TAX LAW CHANGES SINCE THE LAST BASE RATE CASE?

A. Yes. The most significant change to federal tax law since the last distribution base rate case was enactment of the Inflation Reduction Act of 2022 ("IRA"), signed by President Biden on August 16, 2022. Most notably, the IRA imposes a new corporate alternative minimum tax ("AMT"), beginning in 2023, based on 15% of "adjusted financial statement income" ("AFSI"), which is generally accepted accounting principles ("GAAP") net

[6] When COR is removed, the accumulated book depreciation reserve is reduced, causing an increase (approximately $22 million) in the balance of federal excess ADIT related to book-tax depreciation differences that will reverse in the future, and an offsetting decrease (approximately $22 million) in the excess ADIT related to non-depreciation differences.

income with various adjustments including for federal income taxes, tax depreciation, and pension and other post-employment benefits. Corporations are subject to the AMT if their average AFSI over a three-year period exceeds $1 billion. Corporations that are subject to the AMT must pay the greater of 15% of their AFSI or their regular federal income tax liability. Corporations paying the AMT receive an AMT credit, equal to the amount by which the AMT liability exceeds the regular tax liability, to be carried forward, without limitation, and applied against regular federal income tax in a future year in which no AMT is imposed on the corporation. As disclosed in its recently filed the U.S. Securities and Exchange Commission Form 10-K for the year ended December 31, 2022, FirstEnergy currently believes it is more likely than not based on interim guidance issued by the U.S. Treasury in December 2022 that it will be subject to the AMT beginning in 2023. AMT liability must be allocated among members of FirstEnergy's consolidated tax group, including the Company. Because the 2022 tax year is the test year for this base rate case, the AMT is not yet an issue. However, if the Company is allocated AMT liability in 2023 or future years, the corresponding AMT credits could be subject to rate base inclusion in future proceedings. The U.S. Treasury and the IRS are expected to publish additional guidance with respect to the AMT. To the extent such guidance makes changes to the computation of AFSI or AMT from how those amounts are computed under existing guidance, FirstEnergy could be required to change its current AMT estimates or FirstEnergy, and therefore the Company, could no longer be subject to the AMT. There is no stated timetable for the issuance of such guidance.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

SUSAN M. COLFLESH

Concerning: Jurisdictional Separations; Ratemaking Adjustments

March 22, 2023

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Susan M. Colflesh, and my business address is 800 Cabin Hill Drive, Greensburg, Pennsylvania 15601.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT ARE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS?

A. I am employed by FirstEnergy Service Company as a State Regulatory Analyst in the Rates and Regulatory Affairs Department – West Virginia/Maryland. My duties include developing and providing detailed and qualitative analysis on behalf of The Potomac Edison Company ("PE" or "Company") and Monongahela Power Company ("Mon Power"), including quarterly reporting of Federal Energy Regulatory Commission ("FERC") jurisdictional financial data, participating in regulatory proceedings, and developing revenue requirements. I am a graduate of the University of Pittsburgh where I earned a Bachelor of Science in Business Management with an Accounting Emphasis. I have almost 40 years of experience with FirstEnergy Service Company or its predecessor companies. I have worked in various financial positions, including most recently Regulatory Accounting Analyst, before assuming my current role in 2018.

Q. HAVE YOU TESTIFIED OR SUBMITTED TESTIMONY IN OTHER RATE PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes, I have testified on behalf of PE and its affiliate Mon Power before the Public Service Commission of West Virginia in their 2020 Expanded Net Energy Cost Case No. 20-0065-E-ENEC, and in their 2021 Vegetation Management Surcharge Case No. 21-0659-E-P.

Q. **PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.**

A. My testimony will discuss the Company's Jurisdictional Separation Study, as well as a number of going-level adjustments that I am sponsoring.

II. PURPOSE OF TESTIMONY

Q. COULD YOU PLEASE OUTLINE YOUR TESTIMONY?

A. The objective of my testimony is to discuss:

1. The purpose and application of the jurisdictional separation study;
2. The allocation methods used in the jurisdictional separation study;
3. The going-level adjustments which I am sponsoring, listed under Company witness Soltis Exhibit JAS-2, which are related to four primary areas:
    (a) Salaries and Wages and other employee-related costs
    - Adjustment No. 1 Salaries & Wages – test year
    - Adjustment No. 2 Salaries & Wages - 2023
    - Adjustment No. 3 Employee Savings Plan – test year
    - Adjustment No. 4 Employee Savings Plan – 2023
    - Adjustment No. 9 Medical Insurance Expenses
    - Adjustment No. 10 Group Life Insurance Expenses

- Adjustment No. 26 Payroll Taxes on Salaries & Wages – test year
- Adjustment No. 27 Payroll Taxes on Salaries & Wages – 2023

(b) COVID-19 costs, deferrals, and recovery

- Adjustment No. 14 COVID-19 Operation and Maintenance ("O&M") Expense
- Adjustment No. 22 COVID-19 Regulatory Credits
- Adjustment No. 23 Amortization of COVID-19 Regulatory Asset
- Adjustment No. 40 COVID-19 Regulatory Asset – Rate Base

(c) Allocation of Service Company Common Plant to PE

- Adjustment No. 15 Service Company Carrying Charges
- Adjustment No. 20 Depreciation Expense for Service Company Plant Assets
- Adjustment No. 39a Service Company Common Plant
- Adjustment No. 39b Service Company Depreciation Reserve
- Adjustment No. 39c Service Company Accumulated Deferred Income Tax ("ADIT")

(d) Conservation Voltage Reduction Program

- Adjustment No. 21 Conservation Voltage Reduction Program.

Q. HAVE YOU PREPARED OR HAD PREPARED UNDER YOUR SUPERVISION AN EXHIBIT TO ACCOMPANY YOUR TESTIMONY?

A. Yes. Exhibit SMC-1, Jurisdictional Separation Study, was prepared by me or under my supervision and is described in detail in my testimony.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The revenue, investment (or rate base), and expense records for PE are kept in accordance with FERC's Uniform System of Accounts. Since PE does business as an electric public utility in Maryland and West Virginia, as well as owns and operates transmission facilities in Virginia, it is necessary to perform a jurisdictional separation study to determine the fair share attributable to PE's Maryland distribution customers from the total PE amounts. A going-forward or "going-level" separation study was prepared for PE-Maryland, which is included as Exhibit SMC-1. This study was prepared in accordance with historical practices utilized by the Company and accepted by the Public Service Commission of Maryland ("Commission"). The going-level separation study is based on a test year of twelve months actual data for the period of January 1, 2022 through December 31, 2022 ("test year"), reporting booked revenues and expenses as well as reporting adjustments to those revenues and expenses for known and measurable changes. The separation study shows that the current going-level rate of return ("ROR") for PE in Maryland is 2.90%, well below PE's requested ROR of 7.54%.

III. JURISDICTIONAL SEPARATION STUDY

Q. PLEASE DESCRIBE THE SEPARATION STUDY, EXHIBIT SMC-1.

A. During the test year, PE operated at the retail level in both Maryland and West Virginia, and also had wholesale customers subject to FERC jurisdiction in those two states plus

Virginia. Generally, PE's books of account for plant investment and expenses are either directly assigned or allocated to applicable jurisdictions, while most revenues are specifically identified by jurisdiction.

The purpose of the separation study is first to identify rate base, revenues, and expenses that should be either allocated or directly assigned to the Maryland jurisdictional portion of PE's operations for the test year. Those amounts were then further allocated or directly assigned in the separation study to arrive at Maryland distribution-related rate base, revenues and expenses, which also incorporated all the going-level adjustments identified in Company witness Soltis' Exhibit JAS-2.

Q. WAS THE SEPARATION PROCEDURE EMPLOYED IN THIS CASE THE SAME AS THAT USED IN THE PREVIOUS CASE FILED BY PE WITH THIS COMMISSION?

A. Yes, the separation procedure used in this case is the same basic procedure that was used by PE in the Company's previous distribution base rate case in 2018, as adjusted to conform to the Commission's final order in that case.

Q. PLEASE DESCRIBE THE SEPARATION PROCEDURE.

A. The separation procedure consists of a functionalization step and a classification step. In the functionalization step, rate base, expenses, and revenues recorded on the books of PE are separated on a functional basis using the FERC Uniform System of Accounts to identify production, transmission, distribution, customer service, and administrative and general functions. Then the total Company amounts were separated between the jurisdiction being studied (i.e., Maryland) and all others. This separation was performed on the basis of allocation factors developed to assign direct and common costs of providing service equitably to the jurisdiction being considered. In the classification step, common costs were then classified into four major allocation categories (i.e., demand (or capacity)-related, plant-related, labor-related and customer-related) and then allocated appropriately to the Maryland jurisdiction. After arriving at Maryland jurisdictional rate base, revenues, and expenses, the final step applied an additional allocation or direct assignment to determine Maryland distribution-related rate base, revenues and expenses. The two primary allocations used for this last step were derived from the PE FERC Form 1 Distribution of Salaries and Wages and from an internally-developed separation study allocation of Maryland distribution plant to Maryland total plant.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO ALLOCATE DEMAND-RELATED COSTS.

A. The Average Coincident Peak ("ACP") method (consisting of the average of the twelve monthly coincident peaks) was used to allocate demand-related costs. Historically, previous base rate cases in Maryland have used this method, and the Commission has accepted the ACP methodology.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO ALLOCATE PLANT-RELATED COSTS.

A. Directly-assigned plant costs were assigned to Maryland distribution. Common plant-related costs were allocated from PE to Maryland distribution based upon a ratio of Maryland distribution plant to total PE plant. General and intangible plant-related items utilized Salaries and Wages allocators, except for general plant related to land and buildings where service centers are located. Plant related to land and buildings where service centers are located was directly assigned to the appropriate jurisdiction when the service center has no operation that crosses state borders, while service centers that house operations that serve multiple states were allocated using a plant allocator, consistent with the Commission's March 22, 2019 Order in the Company's 2018 base distribution rate case, Case No. 9490.[1]

Q. ARE THERE ANY ADDITIONAL ALLOCATION ITEMS REGARDING PLANT?

Yes. The Company is proposing to include sub-transmission plant for recovery in this distribution rate case. This plant was previously included in the FERC transmission series of accounts; however, lower voltage sub-transmission plant is operated as part of the distribution system and is not reflected for recovery in transmission rates. In the Jurisdictional Separation Study, this plant is included under the Distribution Plant heading on the line called 'Subtransmission Related - 34.5 kV" and is direct assigned to Maryland based on its physical location.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO ALLOCATE LABOR-RELATED COSTS.

A. PE Maryland labor-related costs were determined by an allocator developed within the separation study based upon payroll taxes, functionalizing those expenses based on the PE FERC Form 1 Distribution of Salaries and Wages, and then applying appropriate allocations to each of the functionalized components. Common labor-related costs were

[1] Order at 94.

allocated to Maryland distribution based upon a ratio of Maryland distribution labor to total PE labor, also from the PE FERC Form 1 Distribution of Salaries and Wages.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO ALLOCATE CUSTOMER-RELATED COSTS.

A. Directly assigned customer-related costs were assigned to Maryland distribution. Common customer-related costs are first allocated based on a ratio of the number of PE Maryland customers to total PE customers. Costs not solely distribution-related, such as certain customer accounts and services expenses, were then allocated to Maryland distribution based on a ratio of Maryland distribution plant to total Maryland plant.

Q. WHAT IS THE RESULT OF THE JURISDICTIONAL SEPARATION STUDY?

A. The result of the separation study is a going-level Maryland Distribution report that is the primary input to the class cost of service study ("CCOS"), which is discussed by Company Witness Lyons.

IV. RATEMAKING ADJUSTMENTS

Q. DID YOU INCLUDE ADJUSTMENTS IN YOUR SEPARATION STUDY?

A. Yes, all going-level adjustments were incorporated in the separation study. I will describe a number of going-level adjustments as listed above, with the remaining adjustments described by Company witnesses Ashton, Soltis, and Ward.

Q. CAN YOU EXPLAIN THE FIRST GROUP OF ADJUSTMENTS THAT YOU ARE SPONSORING?

A. Adjustment Nos. 1, 2, 3, 4, 9 and 10 are related to adjustments to the Company's O&M expenses and Payroll Taxes for Salaries and Wages and other employee-related expenses.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 1 (SALARIES AND WAGES)?

A. The purpose of Adjustment No. 1 is to increase PE Maryland distribution O&M expense to reflect the annualized effect of the expense portion of salary and wage increases incurred during the test year. This adjustment applies to Utility Workers Union of America ("UWUA") Local 0102 employees who are classified under a bargaining arrangement and received a 2.5% increase effective May 1, 2022. The adjustment also includes an average 3% increase effective March 1, 2022 for those full-time employees classified as non-bargaining. Because these above-mentioned salary and wage increases were not effective at the beginning of the test year, the salary and wages were annualized for purposes of this adjustment to reflect a full year of the increases. Only straight-time wages (excluding part-time, temporary help and over-time wages) were included in the adjustment.

The O&M annualized salary and wage expense was functionalized to production, transmission, distribution, customer accounts and services, and administrative and general expenses based on the percentage of test year dollars booked to the FERC accounts by: 1) service company-assessed O&M straight-time payroll for PE; 2) PE Payroll Straight-Time Bargaining (account 510010); 3) PE Payroll Straight-Time Non-Bargaining (account 510050); and lastly by 4) all other PE straight-time bargaining and non-bargaining labor accounts. These results were then added together to arrive at the appropriate PE Bargaining and Non-Bargaining Straight-Time functionalizations. Allocations to arrive at the

Maryland jurisdictional and Maryland distribution jurisdictional amounts were also utilized.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 2 (SALARY AND WAGES 2023)?

A. The purpose is to increase PE Maryland distribution O&M expense to reflect the annualized effect of the expense portion of salary and wage increases incurred in the period following the test year but prior to this filing. This salary and wage adjustment includes an average 4% increase effective March 1, 2023 for those full-time employees classified as non-bargaining. Because these salary and wage increases are known and measurable, they need to be added to the going-level salary and wages to reflect the true level of wages that the Company will be paying when new distribution rates go into effect. As with the 2022 increases, these incremental 2023 increases were not effective at the beginning of the test year and were likewise annualized for purposes of this adjustment to reflect a full year of the increases. Again, only straight-time wages (excluding part-time, temporary help and over-time wages) were included in the adjustment, and the functionalization and allocations to Maryland and to Maryland distribution were done the same way as in Adjustment No. 1.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NOS. 3 AND 4 (EMPLOYEE SAVINGS PLAN)?

A. The purpose of Adjustment Nos. 3 and 4 is to increase PE Maryland distribution O&M expense to reflect the annualized effect of the expense portion of salary and wage increases on savings plan costs incurred during the test year and in the post-test-year period before this filing. The Company savings plan matches 50 cents per dollar on the first 6% of employees' 401K savings plan contributions. Consequently, the annualized salary and wage expense increases in Adjustment Nos. 1 and 2 for PE Maryland distribution for bargaining and non-bargaining straight-time were each multiplied by 3%. This results in the savings plan adjustment on annualized salary and wage increases shown on Adjustment No. 3 for test year increases and Adjustment No. 4 for the 2023 increases.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 9 (MEDICAL INSURANCE)?

A. The purpose of Adjustment No. 9 is to adjust test year PE Maryland distribution O&M expense to reflect 2022 going-level medical insurance expenses. The Company is self-insured for its medical and prescription insurance plans, and plan costs are driven by actual experience. Although the Company proactively manages costs and participates in vendor programs to control costs, medical insurance expenses normally do increase on a calendar-year basis. The calculation of Adjustment No. 9 consists of a comparison of medical insurance expenses in 2022 to forecasted medical insurance expenses in 2023, with allocators applied to the difference to arrive at the Maryland distribution jurisdictional amount.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 10 (GROUP LIFE INSURANCE)?

A. The purpose of Adjustment No. 10 is to adjust test year PE Maryland distribution O&M expense to reflect 2022 going-level group life insurance expense. The Company completed a Request for Proposal for life insurance to ensure that costs are competitive. The current contract will expire at the end of 2023. Adjustment No. 10 was calculated in the same fashion as described for Adjustment No. 9.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NOS. 26 AND 27 (PAYROLL TAXES)?

A. The purpose of Adjustment No. 26 is to increase Federal Insurance Contributions Act ("FICA") expense, which is an increase in PE's expense for employer contributions to FICA payroll taxes related to the salary and wage increases in Adjustment No. 1. The purpose of Adjustment No. 27 is to increase FICA expense for employer contributions to FICA payroll taxes related to the salary and wage increases in Adjustment No. 2. The Company FICA contribution rate of 7.65% of gross salaries and wages was applied to Adjustment Nos. 1 and 2 for the PE Maryland distribution total for annualized salaries and wages for both bargaining and non-bargaining straight-time to result in the amount of Adjustment Nos. 26 and 27, respectively.

Q. WHAT AREA OF ADJUSTMENTS DO YOU WISH TO ADDRESS NEXT?

A. Next, I will explain adjustments to test year expenses and rate base that are related to the Company's incremental expenses from the COVID-19 health emergency, including Adjustment Nos. 14, 22, 23, and 40.

On March 16, 2020, Maryland Governor Lawrence Hogan issued an Executive Order prohibiting the termination of residential utility services and the imposition of late fees during the COVID-19 state of emergency. On April 9, 2020, the Commission issued Order No. 89542 authorizing Maryland utilities to create a regulatory asset to record the incremental costs related to COVID-19 incurred by the utilities to ensure that Maryland residents have essential utility services during this period. The Commission acknowledged the potential for significant financial implications that compliance with COVID-19 emergency orders could have on Maryland utilities and found that the creation of regulatory assets would facilitate recovery of costs prudently incurred by utilities in their efforts to serve customers. In addition, the Commission found that the catastrophic health emergency was outside the control of utilities and a non-recurring event.

Beginning in mid-March 2020 and continuing through October 31, 2022, the Company's Maryland distribution operations have incurred and deferred into a regulatory asset for recovery net incremental costs totaling approximately $7.3 million directly related to complying with the various COVID-19 government shut-down orders and precautions. While the Company is still experiencing some impacts from the COVID-19 pandemic, including some restrictions on collections activities beyond October 31, 2022, no additional costs have been or are expected to be deferred beyond that date.

Q. PLEASE DESCRIBE THE COSTS RELATED TO COVID-19 THAT THE COMPANY WISHES TO RECOVER.

A. Incremental costs to the Company include costs directly incurred by the Company, along with the Company's allocated share of costs incurred by FirstEnergy Service Corporation ("FESC") on behalf of the Company. These incremental costs include, but are not limited to, costs to implement social distancing requirements (such as rental of additional vehicles, job trailers, etc.), additional technology costs to effectuate remote tele-work, cleaning and disinfecting of facilities, personal protection equipment (including masks, gloves, hand sanitizer, sanitizing wipes, and thermometers), increased medical-related costs, labor costs in the form of overtime and pandemic recognition awards, and informational communication costs explaining utility safety, COVID-19 response, and customer aid programs. The COVID-19 incremental costs are O&M expense and do not include any capitalized dollars.

The total also includes the incremental impact on uncollectible expense related to temporary discontinuance of service terminations for non-payment. Effective January 1, 2020, FirstEnergy adopted Financial Accounting Standards Board's Accounting Standards Update ("ASU") No. 2016-13, *Financial Instruments – Credit Losses*. ASU No. 2016-13 requires companies to change the method of measuring credit losses, including uncollectible accounts receivable, from an incurred loss basis to a current expected credit loss basis. This change had no significant impact during the first quarter of 2020, where the historical levels of uncollectibles were generally consistent with the expected levels. However, with the full onset of the COVID-19 pandemic in the second quarter of 2020, PE and FirstEnergy examined the impact on customer receivable balances outstanding, and the ability of customers to continue payment. PE and FirstEnergy, (including its Controllers and Revenue Operations Departments) reviewed the allowance for uncollectible customer receivables utilizing a quantitative and qualitative assessment, which included consideration of the outbreak of COVID-19, the impact on customer receivable balances outstanding, and the ability of customers to continue payment. The impact of COVID-19 on customers' ability to pay for service, along with the temporary discontinuance of service terminations for non-payment, resulted in an increase in customer receivable write-offs as compared to historically incurred losses. In order to calculate the additional losses and impacts expected, PE and FirstEnergy analyzed the likelihood of loss based on increases in customer accounts in arrears since the pandemic began in mid-March 2020 as well as what collection methods were suspended that have historically been utilized to ensure payment. Based on this assessment, and in consideration of the factors described above, the Company booked an incremental increase in uncollectible expense. Over the course of the pandemic, this incremental uncollectible expense has been re-evaluated and adjusted as conditions effecting customer arrearages and collections continued to evolve. The incremental impact on uncollectible expense also reflects the decrease from receipt of Recovery for the Economy, Livelihoods, Industries, Entrepreneurs, and Families Act ("RELIEF Act") funds allocated to the Company by Commission Order No. 89856 to reduce or eliminate residential customer utility bill arrearages.

In addition, the moratorium on the imposition of late payment fees in the early days of the pandemic resulted in the Company forgoing receipt of the revenues associated with forfeited discounts, and a reduction in the amount of reconnect fees charged. The cost of these lost revenues was also deferred in the COVID-19 regulatory asset.

Q. PLEASE EXPLAIN THE ALLOCATION OF COVID-19 COSTS TO MARYLAND DISTRIBUTION.

A. Many COVID-19-related costs were incurred directly by Maryland distribution operations and were directly assigned; however, some costs that were administrative and general in nature, such as Family and Medical Leave Administration, could be directly assigned to the Maryland jurisdiction, but then needed to be allocated to the distribution segment based on a Salaries and Wages allocator. Costs incurred by FESC and billed to the Company were first allocated to Maryland based on number of Maryland customers. A second step used a labor allocator to arrive at the distribution portion.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 14 (COVID-19 O&M EXPENSE)?

A. The purpose of Adjustment No. 14 is to adjust test year PE Maryland distribution O&M expense to remove COVID-19 expenses from the test year since such expenses have been deferred into a regulatory asset.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 22 (COVID-19 REGULATORY CREDIT)?

A. The purpose of Adjustment No. 22 is to adjust test year PE Maryland distribution Regulatory Credits to remove the deferral of COVID-19 expenses from the test year. This adjustment is a direct effect from Adjustment No. 14, above, with both adjustments effectively removing the test year effect of the COVID-19 expenses.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 23 (COVID-19 AMORTIZATION)?

A. The purpose of Adjustment No. 23 is to increase going-level expenses to recognize the first year amortization of expenses associated with the requested recovery of the regulatory asset for recovery of incremental COVID-19 costs over a five-year period.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 40 (COVID-19 REGULATORY ASSET)?

A. The purpose of Adjustment No. 40 is to increase plant-in-service for the regulatory asset related to COVID-19, and to increase accumulated depreciation for amortization of first year recovery of the regulatory asset, using a mid-year convention, with the result that the unamortized balance of the regulatory asset is included in the Company's rate base.

Q. WHY IS THE COMPANY PROPOSING TO RECOVER THESE COSTS FROM CUSTOMERS?

A. The Company's COVID-19 costs are additional, extraordinary costs directly related to complying with the various government shut-down orders and COVID-19 precautions. These costs are known and measurable and are amounts actually incurred and booked. These costs were necessary to continue to provide reliable service to customers in a safe manner under extraordinary pandemic circumstances.

Q. WHY DID THE COMPANY SELECT FIVE YEARS AS THE RECOVERY PERIOD?

A. The Company chose five years as a recovery period because the costs are substantial, were incurred over a multi-year period, and this period enables the Company to gradually recover its costs without creating an undue burden on customers, some of whom may still be impacted by the pandemic. In addition, this recovery period is consistent with the Commission's rulings in Baltimore Gas & Electric's Multi-Year Rate Plan Case No. 9645, Potomac Electric Power Company's Multi-Year Rate Plan Case No. 9655, and Delmarva Power's Multi-Year Rate Plan Case No. 9681, where five-year recovery of COVID-19 costs was granted.

Q. ARE THERE OTHER ADJUSTMENTS THAT YOU ARE SPONSORING?

A. Yes, I am sponsoring adjustments related to FirstEnergy Service Company-owned assets that are used by PE, including Adjustment Nos. 39a, 39b, 39c, 15 and 20.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 39a (FESC COMMON PLANT)?

A. The purpose of Adjustment No. 39a is to increase plant-in-service to reflect general and intangible plant-in-service allocated to PE Maryland distribution held by FESC and recorded on FESC's books rather than PE's books. FESC common plant includes but is not limited to software, office furniture and equipment, computer equipment and communications equipment.

The amount of plant-in-service included in this adjustment was arrived at for the Maryland distribution plant by allocating FESC's plant first to PE based on FirstEnergy's Cost Allocation Manual ("CAM")[2] multifactor allocation. From the resulting PE-allocated portion, a second step allocated PE amounts to Maryland, based on an allocation of total plant in Maryland to the total Company plant. The final step was to allocate the Maryland plant to distribution, based on a Salaries and Wages allocation. Since much of the FESC plant is general and intangible plant used by employees, the Salary and Wages allocator was the best choice to equitably allocate these assets.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 39b (FESC DEPRECIATION RESERVE)?

[2] The CAM has been filed in this proceeding as Exhibit TMA-2 to the direct testimony of Company witness Ashton.

A. The purpose of Adjustment No. 39b is to increase the accumulated depreciation reserve included in rate base to reflect the depreciation reserve associated with the common plant allocated in Adjustment No. 39a, and follows the same allocation methodology as used in Adjustment Nos. 39a and described above.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 39c (FESC ADIT)?

A. The purpose of Adjustment No. 39c is to increase the ADIT deduction to rate base to reflect the FESC property-related ADIT's that are associated with the plant-in-service allocated in Adjustment No. 39a. This adjustment again follows the same allocation methodology used in Adjustment Nos. 39a and 39b and detailed above.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 15 (FESC CARRYING CHARGES)?

A. The purpose of Adjustment No. 15 is to adjust the Company's test year O&M to remove carrying charges charged to the Company by FESC. These charges, which reimburse FESC for the cost of having plant used by PE and its affiliated companies on FESC's books, include ADITs, interest, and a return on the assets. As detailed in Adjustment Nos. 39a and 39b above, the Company is proposing to include a share of this plant in PE's rate base. This inclusion in PE's rate base eliminates the need for FESC carrying charges.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 20 (FESC DEPRECIATION AND AMORTIZATION)?

A. The purpose of Adjustment No. 20 is to adjust test year depreciation and amortization expense to include expense for the allocated share of FESC common plant added to PE's rate base as discussed above. Depreciation and amortization expense related to FESC common plant is calculated based on FESC depreciation rates and billed to the operating affiliates, including PE, in FERC Account 923, Outside Services. This adjustment removes the entire amount of these billings from the test year. New depreciation and amortization expense has been calculated based on the Company's depreciation rates requested in this case and detailed in Company witness Spanos's testimony. While the FESC-calculated depreciation and amortization expense is removed from O&M expense, the newly calculated depreciation and amortization expense is added to the test year in FERC accounts 403 Depreciation expense and 404 Amortization expense for general and intangible plant, respectively.

Q. DO YOU HAVE ANY OTHER ADJUSTMENTS?

A. Yes, my final adjustment deals with the Conservation Voltage Reduction ("CVR") program.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 21 (CVR)?

A. The purpose of Adjustment No. 21 is to remove from the test year amounts that were being recovered for the Conservation Voltage Reduction Program. Recovery of the regulatory asset related to this program was granted over three years beginning March 23, 2019 in the Company's last Maryland distribution base rate case, Case No. 9490. As of March 22, 2022 recovery is complete and no further amortization should be reflected in the test year or beyond.

Q. SHOULD THE COMMISSION ADOPT THESE ADJUSTMENTS?

A. Yes. First, they are all known and measurable changes to the test year. Second, the test year financials do not reflect going-level expenses to be incurred by the Company unless these adjustments are adopted in full to reflect the known level of expenses. The full level of expenses is needed to help permit the Company to continue to provide safe and reliable service to its customers. Lastly, the Company will be unable to have the opportunity to earn their allowed rate of return unless these adjustments are made and approved by the Commission in this proceeding.

V. CONCLUSION

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

The Potomac Edison Company
Jurisdictional Separation Study
Maryland - Distribution
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In Whole Dollars

Column (1)	Reference ID (2)	Allocation Factor (3)	Total Company-Per Books (4)	Maryland (5)	West Virginia (6)	Other (7)	MD Distribution Alloc.Factor (8)	MD Distribution (9)	Going Level Adjustment (10)	Adj. No. (11)	MD Distrib. Going Level (12)
Rate Base - 13 Month Average											
Excluding Prior Period for Maryland											
Capacity Allocation Method - Avg. of 12 Monthly Peaks											
SUMMARY OF ALLOCATION											
Electric Plant in Service			$ 2,710,742,554	$ 1,650,818,195	$ 918,513,763	$ 141,410,596		$ 1,400,595,796	$ 73,408,934		$ 1,474,004,730
Reserves for Depreciation & Amortization			1,146,938,030	746,742,882	399,008,417	1,186,732		560,424,574	17,503,714		577,928,288
Net Electric Plant			**1,563,804,524**	**904,075,313**	**519,505,347**	**140,223,864**		**840,171,222**	**55,905,220**		**896,076,441**
				-	-	-		-	-		-
Additions											
Construction Work in Progress			94,967,228	60,842,623	-	34,124,605		42,795,678	7,779,093		50,574,771
Plant Held for Future Use			-	-	-	-		-			-
Prepayments			17,924,746	-	2,745,671	15,179,075		-			-
Working Capital			25,579,607	16,329,597	8,761,875	295,621		3,403,111	13,037,676		16,435,549
Total Additions			**138,471,581**	**77,172,220**	**11,507,546**	**49,599,301**		**46,198,789**	**20,816,769**		**67,010,320**
Deductions											
Accumulated Deferred Taxes			293,096,867	245,024,430	99,359,039	(51,286,603)		210,959,941	5,809,772		225,475,241
Customer Advances for Construction			5,621,654	5,061,698	660,646	(100,690)		5,061,698			5,061,698
Customer Deposits			19,589,516	14,024,604	5,564,912	-		14,024,604			14,024,604
Contractor Retentions			-	-	-	-		-			-
Deferred Investment Tax Credit			-	-	-	-		-			-
Total Deductions			**318,308,037**	**264,110,732**	**105,584,596**	**(51,387,293)**		**230,046,243**	**5,809,772**		**244,561,543**
Total Rate Base			**1,383,968,068**	**717,136,801**	**425,428,296**	**241,210,458**		**656,323,768**	**70,912,216**		**718,525,219**
Operating Revenues	-		**948,557,379**	**601,150,677**	**343,669,321**	**3,737,381**		**138,842,885**	**-**		**138,842,885**
Operating Expenses											
Operation and Maintenance			717,381,346	456,583,358	249,006,880	11,791,108		59,657,983	(3,002,598)		56,655,385
Depreciation and Amortization Expense			59,010,352	32,835,145	24,627,671	1,547,535		27,614,934	6,207,090		33,822,024
Regulatory Debits			10,047,784	2,005,606	7,605,978	436,200		938,317	(938,317)		-
Regulatory Credits			14,926,305	16,193,844	(1,244,383)	(23,156)		(3,215,103)	4,503,455		1,288,352
Accretion expense			22,788	-	-	22,788		-	-		-
Taxes - Other			47,813,320	34,840,619	12,622,989	349,712		30,563,131	44,187		30,607,318
Total Operating Expenses			**849,201,894**	**542,458,571**	**292,619,136**	**14,124,188**		**115,559,262**	**6,813,818**		**122,373,079**
Operating Income Before Tax			**99,355,485**	**58,692,106**	**51,050,186**	**(10,386,807)**		**23,283,624**	**(6,813,818)**		**16,469,806**
Income Taxes											
State			(235,117)	(337,688)	92,694	9,877		(2,621,445)	(412,619)		(3,020,652)
Federal			1,065,836	(1,253,802)	772,291	(4,427,352)		(6,122,265)	(963,652)		(7,054,596)
Income Taxes Deferred - Net			19,067,939	9,201,689	4,880,728	4,985,522		8,298,486			8,298,486
Amortization of Investment Credit			-	-	-	-		-			-
Total Income Taxes			**19,898,658**	**7,610,200**	**5,745,713**	**568,047**		**(445,223)**	**(1,376,271)**		**(1,776,762)**
Operating Income			**79,456,827**	**51,081,907**	**45,304,473**	**(10,954,854)**		**23,728,847**	**(5,437,547)**		**18,246,568**
Allowance for Funds Used During Construction			5,790,352	3,709,703	-	2,080,649		2,609,343			2,609,343
Interest on Customer Deposits			(22,016)	(17,180)	(4,837)	-		(17,180)			(17,180)
											-
Return			**$ 85,225,162**	**$ 54,774,430**	**$ 45,299,636**	**$ (8,874,205)**		**$ 26,321,010**	**$ (5,437,547)**		**$ 20,838,731**
Rate of Return			**6.158%**	**7.638%**	**10.648%**	**-3.679%**		**4.010%**	**-7.668%**		**2.900%**

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In Whole Dollars

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Electric Plant in Service											
Production Plant		D10	-	-	-	-		-	-		-
Transmission Plant											
Transmission		RBD10	518,587,259	242,449,915	137,731,964	138,405,380	Direct-Other	-			-
ARC		Direct-other	3,431	-	-	3,431	Direct-Other	-			-
Total Transmission Plant			**518,590,690**	**242,449,915**	**137,731,964**	**138,408,811**		**-**	**-**		-
Distribution Network		Direct	1,747,428,288	1,083,770,058	662,992,256	665,973	Direct-MD	1,083,770,058			1,083,770,058
Trans.-Subtransmission Related - 34.5 kV		Direct	313,121,613	249,787,384	63,292,967	41,262	Direct-MD	249,787,384			249,787,384
Reliability Projects in Test Year Adj.									18,693,027	(31)	18,693,027
Reliability Projects Post Test Adj.									18,102,746	(32a)	18,102,746
Total Distribution Plant			**2,060,549,901**	**1,333,557,442**	**726,285,224**	**707,235**		**1,333,557,442**	**36,795,773**		**1,370,353,215**
General Plant											
Structures & Buildings		Direct	43,226,588	24,410,446	17,314,206	1,501,937	S&W	21,874,319			21,874,319
Other		TX60	48,004,714	27,384,306	20,202,489	417,919	S&W	24,539,209			24,539,209
Reliability Projects' in Test Year Adj.									451,182	(31)	451,182
Reliability Projects Post Test Adj.									484,460	(32a)	484,460
Allocation of FE Service Company Plant Adj.									10,996,594	(39a)	10,996,594
ARC		Direct other	23,440	-	-	23,440	Direct - Other	-			-
Total General Plant			**91,254,742**	**51,794,751**	**37,516,696**	**1,943,295**		**46,413,528**	**11,932,236**		**58,345,763**
Intangible Plant		TX60	40,347,220	23,016,086	16,979,880	351,254	S&W	20,624,826			20,624,826
Reliability Projects in Test Year Adj.									984,519	(31)	984,519
Reliability Projects Post Test Adj.									627,315	(32a)	627,315
Non Eligible amounts									(115,221)	(42)	(115,221)
Allocation of FE Service Company Plant Adj.									14,397,793	(39a)	14,397,793
Subtotal Plant			**2,710,742,554**	**1,650,818,195**	**918,513,763**	**141,410,596**		**1,400,595,796**	**64,622,415**		**1,465,218,211**
Regulatory Assets / Liabilities											
COVID-19 Regulatory Asset Adj									7,260,229	(40)	7,260,229
MD Electric Vehicle Program Reg Asset Adj									1,526,290	(41)	1,526,290
Total Regulatory Assets									8,786,519		8,786,519
Total Electric Plant in Service			**2,710,742,554**	**1,650,818,195**	**918,513,763**	**141,410,596**		**1,400,595,796**	**73,408,934**		**1,474,004,730**
Accumulated Reserves for Depreciation											
Production		D10		-		-		-			-
Transmission											
Network		RBD10	278,554,092	182,079,668	96,474,424	-	Direct-Other	-			-
ARC		Direct-Other	-	-	-	-	Direct-Other	-			-
Total Transmission			278,554,092	182,079,668	96,474,424	-		-	-		-
Distribution											
Network		Direct	678,378,986	429,482,117	248,835,326	61,543	Direct-MD	429,482,117			429,482,117
Trans.-Subtransmission Related-34.5 kV		Direct	115,599,150	94,383,818	21,211,211	4,121	Direct-MD	94,383,818			94,383,818
Reliability Projects in Test Year Adj.									438,488	(33)	438,488
Reliability Projects Post Test Adj.									388,483	(34)	388,483
Total Distribution			793,978,136	523,865,935	270,046,537	65,664		523,865,935	826,971		524,692,906
General Plant											
Structures & Buildings		Direct	21,328,543	10,519,338	10,150,217	658,989	S&W	9,426,429			9,426,429
Common		TX60	26,308,693	15,007,803	11,071,852	229,038	S&W	13,448,565			13,448,565
Reliability Projects in Test Year Adj.									125,199	(33)	125,199
Reliability Projects Post Test Adj.									8,531	(34)	8,531
Allocation of FE Service Company Plant Adj.									4,497,512	(39b)	4,497,512
ARC				-	-	-	Direct-Other	-			-
Total General			47,637,236	25,527,141	21,222,069	888,027		22,874,994	4,631,243		27,506,237

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12 Months Ended December 31, 2022
In Whole Dollars

Column (1)	Reference ID (2)	Allocation Factor (3)	Total Company-Per Books (4)	Maryland (5)	West Virginia (6)	Other (7)	MD Distribution Alloc.Factor (8)	MD Distribution (9)	Going Level Adjustment (10)	Adj. No. (11)	MD Distrib. Going Level (12)
Depreciation Reserve on Regulatory Assets											
COVID-19 Regulatory Asset Depreciation Adj									726,023	(40)	726,023
MD Electric Vehicle Program Reg Asset Depr. Adj									152,629	(41)	152,629
Total Reg Asset Depreciation Reserve									878,652		878,652
CWIP Depr Reserve									162,583	(34)	162,583
Total Depreciation			1,120,169,464	731,472,744	387,743,030	953,690		546,740,930	6,499,449		553,240,378
Accumulated Amortization Intangible Plant		TX60	26,768,566	15,270,138	11,265,387	233,041		13,683,644			13,683,644
Reliability Projects' in Test Year Adj.									32,530	(33)	32,530
Reliability Projects Post Test Adj.									34,930	(34)	34,930
Non Eligible Amounts									(12,062)	(42)	(12,062)
Allocation of FE Service Company Plant Adj.									10,948,867	(39b)	10,948,867
Total Depreciation & Amortization			**1,146,938,030**	**746,742,882**	**399,008,417**	**1,186,732**		**560,424,574**	**17,503,714**		**577,928,288**
Total Net Electric Plant			**1,563,804,524**	**904,075,313**	**519,505,347**	**140,223,864**		**840,171,222**	**55,905,220**		**896,076,441**
Additions											
Construction Work in Progress											
Production		D10	-	-		-		-			-
Transmission		RBD10	25,379,467	16,589,542		8,789,925	Direct other	-			-
Distribution		Direct	46,631,508	30,225,453		16,406,055	Direct - MD	30,225,453			30,225,453
Terminal treatment of post test year reliability projects									7,779,093	(32b)	7,779,093
General & Intangible		GP60	22,956,253	14,027,628		8,928,625	S&W	12,570,225			12,570,225
Total Construction Work in Progress			**94,967,228**	**60,842,623**	**-**	**34,124,605**		**42,795,678**	**7,779,093**		**50,574,771**
Plant Held for Future Use											
Production		D10	-	-	-	-		-			-
Transmission		GP20	-	-	-	-	Direct Other	-			g
Distribution		Direct	-	-	-	-	Direct MD	-			-
Total Plant Held for Future Use			-	-	-	-		-			-
Working Capital											
Fuel In Stock			-	-	-	-		-			-
Plant Materials and Supplies Adj.		D10	-	-	-	-		-	13,191,398	(35)	13,191,398
Prepayments											
Commission Assessments		Direct	494,917	-	382,082	112,835	Direct-MD	-			-
WV Weatherization Program		Direct-WV	35,673	-	35,673	-	Direct-Other	-			-
Edison Electric Dues (Operating)		GP01	49,405	-	16,741	32,665	MDGP01	-			-
Plant Related		GP01	6,820,801	-	2,311,175	4,509,626	MDGP01	-			-
Labor Related		TX60	-	-	-	-	Direct-Other	-			-
Purchased Power		Direct-Other	5,560,365	-	-	5,560,365	Direct-Other	-			-
Other (MD Related, Nonoperating)		Direct-Other	4,963,584	-	-	4,963,584		-			-
Total Prepayments			17,924,746	-	2,745,671	15,179,075		-	-		-
Working Cash Calculation											
Total Operating and Maintenance Expense			717,381,346	456,583,358	249,006,880	11,791,108		59,657,983	(3,002,598)		56,655,385
Taxes Other			47,813,320	34,840,619	12,622,989	349,712		30,563,131	44,187		30,607,318
State Taxes			(235,116)	(337,688)	92,694	9,877		-			-
Federal Taxes			1,065,836	(1,253,802)	772,291	(4,427,352)		-			-
Interest Expense-Common			29,488,167	17,958,032	9,991,833	1,538,301		16,092,280	(1,974,939)		14,117,341
Interest Expense-Customer Deposits			22,016	17,180	4,837	(0)		17,180			17,180
Interest Exp-AFUDC			(1,667,739)	(1,015,638)	(565,100)	(87,001)		(714,383)			(714,383)
Dividends on Preferred Stock			-	-	-	-		-			-
Total Cash Expense			793,867,830	506,792,061	271,926,423	9,174,646		105,616,191	(4,933,350)		100,682,840
Daily Cash Requirement			2,174,980	1,388,471	745,004	25,136		289,359	(13,516)		275,843
Total Cash Working Capital			25,579,607	16,329,597	8,761,875	295,621		3,403,111	(158,960)	(36)	3,244,151
Lead / Lag Days	11.76								(5,105,826)		(5,105,826)
Total Working Capital			43,504,353	16,329,597	11,507,546	15,474,696		3,403,111	13,032,438		16,435,549
Total Additions			**138,471,581**	**77,172,220**	**11,507,546**	**49,599,301**		**46,198,789**	**20,811,531**		**67,010,320**

The Potomac Edison Company
Jurisdictional Separation Study
Maryland - Distribution
12 Months Ended December 31, 2022
In Whole Dollars

Column (1)	Reference ID (2)	Allocation Factor (3)	Total Company-Per Books (4)	Maryland (5)	West Virginia (6)	Other (7)	MD Distribution Alloc.Factor (8)	MD Distribution (9)	Going Level Adjustment (10)	Adj. No. (11)	MD Distrib. Going Level (12)
Deductions											
Accumulated Deferred Taxes											
Plant Related - Federal & State		GP01	326,328,659	198,731,262	110,169,584	17,427,813	MDGP01	178,084,046			178,084,046
Plant Related - WV		GP01	-	-	-	-	MDGP01	-			-
Plant Related - MD		Direct	27,318,326	27,318,326	-	-	MDGP01	24,480,084			24,480,084
Labor Related - Federal & State		TX60	27,985,101	15,964,111	-	12,020,990	S&W	14,305,517			14,305,517
Labor Related - MD		Direct	2,068,538	2,068,538	-	-	S&W	1,853,627			1,853,627
Customer Related		GP01	-	-	-	-		-			-
CIACS - Federal		GP30 - WV only	(30,670,689)	-	(10,810,545)	(19,860,144)	Direct- Other	-			-
CIACS - MD		Direct	(3,258,478)	-	-	(3,258,478)	Direct- Other	-			-
Direct-MD Distribution Related		Direct	942,194	942,194	-	-	Direct-MD	942,194			942,194
Direct - WV		Direct- WV	-	-	-	-	Direct- WV	-			-
Direct - Other		Direct-Other	(57,616,785)	-	-	(57,616,785)	Direct- Other	-			-
Reliability Projects in Test Year Adj.									1,737,865	(37)	1,737,865
Reliability Projects Post Test Adj.									2,991,255	(38)	2,991,255
Service Company allocation of ADIT									1,080,653	(39c)	1,080,653
Total Accumulated Deferred Taxes			293,096,866	245,024,430	99,359,039	(51,286,603)		219,665,469	5,809,772		225,475,241
Customer Advances for Construction		Direct	5,621,654	5,061,698	660,646	(100,690)	Direct-MD	5,061,698			5,061,698
Customer Deposits		Direct	19,589,516	14,024,604	5,564,912	-	Direct-MD	14,024,604			14,024,604
Contractor Retentions			-	-	-	-		-			-
Deferred Investment Tax Credit		GP01	-	-	-	-		-			-
Total Deductions			**318,308,036**	**264,110,732**	**105,584,596**	**(51,387,293)**		**238,751,771**	**5,809,772**		**244,561,543**
Total Rate Base			**1,383,968,069**	**717,136,801**	**425,428,296**	**241,210,458**		**647,618,240**	**70,906,978**		**718,525,219**
Operating Revenues											
Sales of Electricity											
Sales to Ultimate Customers											-
Generation / SOS (MD)	RVSE1	Direct	277,743,980	277,743,979	-	1	Direct-Other	-			-
Distribution (MD)	RVSE1a	Direct	134,248,154	134,248,154	-	(0)	Direct-MD	134,248,154			134,248,154
Transmission & Ancillary	RVSE1B	Direct	14,537,944	14,537,944	-	0	Direct-Other	-			-
Bundled (WV)	RVSE1	Direct	334,782,948	-	334,782,948	0	Direct-Other	-			-
PURPA Generation (MD)	RVSE3	Direct	28,278,679	28,278,679	-	(0)	Direct-Other	-			-
Local Excise Tax (WV)	RVSE6	Direct	1,955,942	-	1,955,942	0	Direct-Other	-			-
WV Equalization	RVSE7	Direct	(22,084,248)	-	(22,084,248)	(0)	Direct-Other	-			-
MD Environmental Surcharge	RVSE8	Direct	978,222	978,222	-	(0)	Direct-Other	-			-
EmPower MD Surcharge	RVSE9	Direct	36,583,369	36,583,369	-	(0)	Direct-Other	-			-
MD Electric Vehicle	RVSE13	Direct	40,823	40,823	-	0	Direct-Other	-			-
MD Electric Distribution Infrastructure Surcharge	RSVE15	Direct	3,822,612	3,822,612	-	-	Direct-Other	-			-
Tax Reform Reduction to revenues	RVSEARAM	Direct	(2,173,045)	-	(2,173,045)	0	Direct-Other	-			-
WV Vegetation Management Surcharge	RVSE11	Direct	28,291,556	-	28,291,556	0	Direct-Other	-			-
Total Sales to Ultimate Customers			**837,006,936**	**496,233,783**	**340,773,152**	**1**		**134,248,154**	**-**		**134,248,154**
Sales for Resale											
Wholesale	RVSR1	Direct-Other	118,678	-	-	118,678	Direct-Other	-			-
MD Solar	RVSR1a	Direct	60,845	60,845	-	0	Direct-Other	-			-
PJM Cap Res Defic & RPM Auction	RVSR9	Direct	-	-	-	-	Direct-Other	-			-
Borderlines	RVSR12	Direct	1,438,912	1,438,912	-	0	Direct-Other	-			-
Spot Market	RVSR13	Direct	-	-	-	-	Direct-Other	-			-
PJM Trans-Other	RVSR14	Direct	-	-	-	-	Direct-Other	-			-
PJM Revenues for Energy Eff. Programs	RVSR15	Direct	83,824	56,411	27,413	(0)	Direct-Other	-			-
Warrior Run	RV5WR	Direct	87,580,326	87,580,326	-	-	Direct-Other	-			-
Total Sales for Resale			**89,282,585**	**89,136,493**	**27,413**	**118,678**		**-**	**-**		**-**
Total Sales of Electricity			**926,289,521**	**585,370,276**	**340,800,566**	**118,680**		**134,248,154**	**-**		**134,248,154**

The Potomac Edison Company
Jurisdictional Separation Study
Maryland - Distribution
12 Months Ended December 31, 2022
In Whole Dollars

Column (1)	Reference ID (2)	Allocation Factor (3)	Total Company-Per Books (4)	Maryland (5)	West Virginia (6)	Other (7)	MD Distribution Alloc.Factor (8)	MD Distribution (9)	Going Level Adjustment (10)	Adj. No. (11)	MD Distrib. Going Level (12)
PJM Transmission Revenues											
PJM Transmission	RVT1	Direct	-	-	-	-	Direct-Other	-			-
PJM Ancillary Serv Rev-WV Warrior Run	RVT2WR	Direct	716,596	716,596	-	0	Direct-Other	-			-
Aff Trans., Point to Point, Seams	RVT3B	Direct	814,183	424,582	211,226	178,375	Direct-Other	-			-
PJM-ARR-REV	RVT5	Direct	70,818	70,818	-	0	Direct-Other	-			-
PJM Network Transmission	RVT6	Direct	14,938,715	9,807,891	(860,222)	5,991,047	Direct-Other	-			-
Total PJM Transmission Revenues			16,540,312	11,019,886	(648,997)	6,169,422		-	-		-
Other Revenues (450, 451, 454, 456)											
Forfeited Discounts/Late Payment Charges	RVO1	Direct	2,291,690	1,019,201	1,272,489	(0)	MDGP01	913,311			913,311
Rent - Distribution Plant Related	RVO2	Direct	4,068,635	2,338,995	1,729,640	(0)	Direct-MD	2,338,995			2,338,995
Rent Property, Land and Buildings & Temp. Fac.	RVO2B	Direct	41,158	29,233	1,600	10,326	MDGP50	26,195			26,195
Misc. Service Rev.-Distribution Related	RVO5	Direct	764,858	431,643	333,234	(19)	Direct-MD	431,643			431,643
Misc. Service Rev. Other	RVO11	Direct	1,943	-	1,943	(0)	Direct-Other	-			-
Other - Customer - Distribution Related	RVO6	C10	6,000	3,916	1,360	724	Direct MD	3,916			3,916
Other - Common - Transmission Related	RVO7	D10	11,815	5,524	1,467	4,824	Direct-Other	-			-
Wholesale Cust Dist OSFC & Misc MD Rev	RVO8	Direct	880,670	880,670	-	(0)	Direct-MD	880,670			880,670
Ft. Martin Equalization	RVO9	Direct	(2,566,575)	-	-	(2,566,575)	Direct-Other	-			-
PJM Trans-AYE (PEPCO)	RVO10	Direct	59,185	51,333	7,851	0	Direct-Other	-			-
Misc WV Revenues	RVO12	Direct	168,167	-	168,168	(1)	Direct-Other	-			-
Total Other Revenues			5,727,546	4,760,515	3,517,752	(2,550,721)		4,594,731	-		4,594,731
Total Operating Revenues			948,557,379	601,150,677	343,669,321	3,737,381		138,842,885	-		138,842,885
Operating Expenses											
Operation and Maintenance											-
Power Prod. Steam - Rents - Leased Generation	EPR2	Direct	233,892,506	-	233,892,506	-	Direct-Other	-			-
Purchased Power											-
Purchased Power - Retail Load	EPP1	Direct	227,558,716	227,557,889	826	1	Direct-Other	-			-
ENEC-Affiliated PP WV Securitization Expense	EPP1B	Direct	5,558,411	-	-	5,558,411	Direct-Other	-			-
ENEC-Borderline Purchases-Meter Reading	EPP3	Direct	181,685	-	181,685	-	Direct-Other	-			-
Purchased Power - Aff. Borderlines	EPP4	Direct	1,776,366	1,776,366	-	-	Direct-Other	-			-
NUG Expenses & Capacity Purchases	EPP5	Direct	119,456,612	119,456,612	-	(0)	Direct-Other	-			-
Purchased power for EV Charging stations	EPP14	Direct	84,479	84,479	-	0	Direct-Other	-			-
ENEC - Spot Mkt., PJM Gen Exp Other, Renew.Energy	EPP12	Direct	4,719,321	4,740,629	(21,308)	(0)	Direct-Other	-			-
ENEC - PJM RPN Inadvert Interchange (Dmd Related)	EPP13	Direct	(146)	(149)	3	0	Direct-Other	-			-
Total Purchased Power			359,335,444	353,615,826	161,206	5,558,412		-	-		-
Other Expenses							Direct-Other				
MD- Settlement, Gen Mkt, Admin, Cap Purch	EPP12B	Direct	15,357,428	15,357,428	-	-	Direct-Other	-			-
ENEC-Deferred Power Cost	EPP7	Direct	(46,486,415)	34,912	(46,486,415)	(34,912)	Direct-Other	-			-
MD Warrior Run Capacity	EPP2	Direct	(3,651,333)	(3,651,333)	-	-	Direct-Other	-			-
Misc. - Capacity Related	EPP9	RD10	177,242	85,851	61,257	30,134	Direct-Other	-			-
Total Other Expenses			(34,603,078)	11,826,857	(46,425,158)	(4,777)		-	-		-
						-					
Total Production O&M			**558,624,872**	**365,442,683**	**187,628,554**	**5,553,635**		**-**	**-**		**-**
Transmission O&M	ET1	GP20	15,328,911	7,166,525	4,136,913	4,025,473	Direct-Other	-			-
PJM Transmission Expense						-	Direct-Other	-			-
Generation Deactivation Charges	ET1B	Direct	-	-	-	-	Direct-Other	-			-
Transmission Exp--MD & VA Veg Mgmt	ET8	Direct	1,717,802	-	1,717,802	-	Direct-Other	-			-
Market Admin., Monitoring & Compliance	ET2	Direct	177,940	14,539	163,401	(0)	Direct-Other	-			-
Transmission Enhancement Charges	ET7	Direct	32,518,476	17,951,288	14,567,188	0	Direct-Other	-			-
PJM Ancillary Services - Sch 9 Reliability	ET10	Direct	626	626	-	(0)	Direct-Other	-			-
PJM Ancillary Services - Sch 1 - Sch 9	ET9	Direct	14,606	14,666	(61)	1	Direct-Other	-			-
Miscellaneous Transmission Exp	ET6	Direct	422,078	277,567	78,900	65,611	Direct-Other	-			-
Total PJM Transmission			34,851,528	18,258,687	16,527,230	65,611		-			-
									-		
Total Transmission O&M			**50,180,439**	**25,425,212**	**20,664,143**	**4,091,084**		**-**	**-**		**-**

The Potomac Edison Company
Jurisdictional Separation Study
Maryland - Distribution
12 Months Ended December 31, 2022
In Whole Dollars

Column (1)	Reference ID (2)	Allocation Factor (3)	Total Company-Per Books (4)	Maryland (5)	West Virginia (6)	Other (7)	MD Distribution Alloc.Factor (8)	MD Distribution (9)	Going Level Adjustment (10)	Adj. No. (11)	MD Distrib. Going Level (12)
Distribution											
Common	ED1	Direct	47,011,905	33,287,329	13,704,073	20,503	Direct - MD	33,287,329			33,287,329
Distribution Exp - WV Veg Mgt Surcharge	**ED2**	Direct-Other	13,517,159	-	13,517,159	-		-			-
Salaries and Wages Adj. - 2022									255,885	(1)	255,885
Salaries and Wages Adj. - 2023									321,723	(2)	321,723
Storm Damage Adj.									(55,154)	(5)	(55,154)
Advertising Expense Adj.									(5,138)	(6)	(5,138)
COVID-19 Expense Adj									(20,841)	(14)	(20,841)
Total Distribution O&M			**60,529,063**	**33,287,329**	**27,221,232**	**20,503**		**33,287,329**	**496,475**		**33,783,804**
Customer Accounts and Services											
Uncollectibles	ECA1	Direct	2,824,842	3,235,707	(410,864)	-	Direct - MD	3,235,707			3,235,707
COVID-19 Expense Adj									(2,103,093)	(14)	(2,103,093)
Meter Reading & Billing	ECA2	C10	10,431,953	6,808,962	3,622,871	120	Direct - MD	6,808,962			6,808,962
Postage Expense Adj.									46,132	(7)	46,132
COVID-19 Expense Adj									(877)	(14)	(877)
Misc. Cust Serv and Info Exp	ECA3	C10	3,655,955	2,386,251	1,269,662	42	Direct - MD	2,386,251	(4,438)	(6)	2,381,813
Customer Assistance	ECA4	C10	357,584	233,396	124,184	4	Direct - MD	233,396			233,396
Customer Rebates & Incentives	ECA5	Direct	4,263,820	4,258,262	5,558	-	Direct - Other	-			-
Sales Expense	ECA6	C10	2	1	1	0	Direct - MD	1			1
All Other Cust Accts & Services	ECA7	Direct	-	-	-	-	Direct - MD	-			-
Other-Direct to Other	ECA9	Direct	45,245	45,245	-	-	Direct Other	45,245	(45,245)	(6)	-
Total Customer Accounts and Services			**21,579,401**	**16,967,824**	**4,611,412**	**166**		**12,709,562**	**(2,107,521)**		**10,602,041**
Administrative & General											
Commission Expense Adj.	EAG2	Direct	2,308,937	1,284,232	1,024,751	(46)	Direct - MD	1,284,232	41,952	(8)	1,326,184
Rate Case Expense Adj.									423,557	(13)	423,557
Employee Benefits (Acct. 926)	EAG3	TX60	(6,351,959)	(3,623,526)	(2,654,827)	(73,607)	S&W	(3,247,059)			(3,247,059)
Employee Savings Plan Adj. - Test Year									7,677	(3)	7,677
Employee Savings Plan Adj. - 2023									9,415	(4)	9,415
Medical Insurance Expense Adj.									58,034	(9)	58,034
Group Life Insurance Expense Adj.									(543)	(10)	(543)
Pension/OPEB Expenses Adj.									962,253	(11) (12)	962,253
COVID-19 Expense Adj									(55,050)	(14)	(55,050)
Outside Services	EAG9	A&G	17,794,077	11,207,305	6,088,553	498,219	MDGP01	9,710,582			9,710,582
Outside Services - MD & VA Transmission	EAG10	Direct Other	1,256,470	-	-	1,256,470	Direct Other	-			-
Service Company Carrying Charges Adj.									(2,743,458)	(15)	(2,743,458)
COVID-19 Expense Adj									(83,458)	(14)	(83,458)
General Advertising Expense	EAG6	Direct	156,193	57,236	70,628	28,329	Direct - MD	57,236			57,236
Advertising Expense Adj.									(11,930)	(6)	(11,930)
Dues and Memberships	EAG12	Direct-Other	228,249	-	-	228,249					-
Administrative and General Salaries	EAG4	TX60	7,424,366	4,235,289	3,103,044	86,033	S&W	3,795,263			3,795,263
All Other O&M	EAG11	A&G	3,651,237	2,299,774	1,249,390	102,073	S&W	2,060,838			2,060,838
Total Administrative & General			**26,467,570**	**15,460,310**	**8,881,539**	**2,125,721**		**13,661,093**	**(1,391,552)**		**12,269,540**
Total Operation and Maintenance			**717,381,346**	**456,583,358**	**249,006,880**	**11,791,108**		**59,657,983**	**(3,002,598)**		**56,655,385**

The Potomac Edison Company
Jurisdictional Separation Study
Maryland - Distribution
12 Months Ended December 31, 2022
In Whole Dollars

Column (1)	Reference ID (2)	Allocation Factor (3)	Total Company-Per Books (4)	Maryland (5)	West Virginia (6)	Other (7)	MD Distribution Alloc.Factor (8)	MD Distribution (9)	Going Level Adjustment (10)	Adj. No. (11)	MD Distrib. Going Level (12)
Operating Expenses											
Depreciation Expense											
Production Depreciation Expense		D10	-	-	-	-		-			
Transmission Depreciation Expense											-
Common		RBD10	8,277,384	4,774,214	2,050,826	1,452,344	Direct Other	-			-
Total Transmission			8,277,384	4,774,214	2,050,826	1,452,344		-	-		-
Distribution											
Distribution Network		Direct	36,695,751	19,067,875	17,610,253	17,623	Direct - MD	19,067,875			19,067,875
Subtrans related - 34.5 Kv		Direct	6,153,707	4,550,384	1,603,323	-	Direct - MD	4,550,384			4,550,384
Adjust for new depreciation rates.									4,251,230	(16)	4,251,230
Test year distribution reliability projects adj.									438,488	(17)	438,488
Post-test year distribution reliability projects adj.									388,483	(18)	388,483
Total Distribution			42,849,458	23,618,259	19,213,576	17,623		23,618,259	5,078,200		28,696,459
General Plant											
Structures & Buildings		Direct	358,293	149,910	196,328	12,055	Direct	149,910			149,910
Common		TX60	3,678,645	2,098,484	1,548,135	32,025	S&W	1,880,462			1,880,462
Adjust for new depreciation rates.									(194,912)	(16)	(194,912)
Test year distribution reliability projects adj.									125,199	(17)	125,199
Post-test year distribution reliability projects adj.									8,531	(18)	8,531
Service Company Plant Allocation Adj									978,101	(20)	978,101
Total General			4,036,938	2,248,394	1,744,463	44,081		2,030,372	916,920		2,947,291
Intangible Plant		TX60	3,846,572	2,194,278	1,618,806	33,487	S&W	1,966,303			1,966,303
Service Company Plant Allocation Adj									1,037,987	(20)	1,037,987
Adjust for new depreciation rates.									(1,056,059)	(16)	(1,056,059)
Test year distribution reliability projects adj.									32,530	(17)	32,530
Post-test year distribution reliability projects adj.									34,930	(18)	34,930
Post-test year distribution reliability projects adj.									162,583	(18)	162,583
Total Depreciation & Amortization Expense			59,010,352	32,835,145	24,627,671	1,547,535		27,614,934	6,207,090		33,822,024
Amortization of Deferred Fuel Balance		Direct-WV	-	-		-		-			-
Total Depreciation & Amortization Expense			**59,010,352**	**32,835,145**	**24,627,671**	**1,547,535**		**27,614,934**	**6,207,090**		**33,822,024**
Regulatory Debits											
Transmission-MD	REGDR1	Direct	(148,528)	(148,528)	-	0	Direct-other	-			-
Vegetation Mgmt - MD & VA	REGDR5	Direct	1,652,017	1,215,817	-	436,200	Direct-other	-			-
Offset to Reg Liab for Sponsorships, Lobbying etc.	REGDR6	Direct	1,048,065	938,317	109,748	0	Direct - MD	938,317			938,317
Adjust for out of period									(938,317)	(43)	(938,317)
Vegetation Mgmt Surcharge - WV	REGDR2	Direct	7,496,230	-	7,496,230	(0)	Direct-other	-			-
Total Regulatory Debits			**10,047,784**	**2,005,606**	**7,605,978**	**436,200**		**938,317**	**(938,317)**		**-**

Column (1)	Reference ID (2)	Allocation Factor (3)	Total Company-Per Books (4)	Maryland (5)	West Virginia (6)	Other (7)	MD Distribution Alloc.Factor (8)	MD Distribution (9)	Going Level Adjustment (10)	Adj. No. (11)	MD Distrib. Going Level (12)
Regulatory Credit											
Storm Deferral WV	REGCR1	Direct	(3,183,616)	-	(3,183,616)	(0)	Direct-other	-			-
MD Empower	REGCR2	Direct	18,907,756	18,907,756	-	(0)	Direct-other	-			-
Amortization Env. Control Prop - WV	REGCR3	Direct	-	-	-	-	Direct-other	-			-
MD EDIS	REGCR6	Direct	(393,539)	(393,539)	-	0	Direct - MD	(393,539)			(393,539)
Vegetation Mgmt - MD & VA	REGCR5	Direct	-	-	-	-	Direct-other	-			-
MD Electric Vehicle Program	REGCR7	Direct	(527,034)	(527,034)	-	0	Direct - MD	(527,034)			(527,034)
Electric Vehicle Program Going Level Adj.									527,034	(25)	527,034
Electric Vehicle Program Amortization									305,258	(24)	305,258
MD Conservation Voltage Reduction (CVR)	REGCR14	Direct	33,050	33,050	-	0	Direct MD	33,050			33,050
CVR Adj									(33,050)	(21)	(33,050)
Deferral of Rate Case Expenses	REGCR4	Direct	(73,049)	(64,261)	(8,789)	0	Direct MD	(64,261)			(64,261)
Rate Case Expense Going Level Adj.									(11,152)	(19)	(11,152)
ARO Accretion	REGCR9	Direct	(23,156)	-	-	(23,156)	Direct-other	-			-
Transmission	REGCR11	Direct	937,767	517,250	420,517	0	Direct-other	-			-
COVID-19	REGCR12	Direct	(751,874)	(2,279,378)	1,527,504	(0)	Direct MD	(2,263,319)			(2,263,319)
COVID-19 Going Level Adj.									2,263,319	(22)	2,263,319
COVID-19 Amortization									1,452,046	(23)	1,452,046
Total Regulatory Credits			**14,926,305**	**16,193,844**	**(1,244,383)**	**(23,156)**		**(3,215,103)**	**4,503,455**		**1,288,352**
Taxes - Other											
Payroll Taxes											-
Production	OTPAY1	GP10	-	-	-	-	Direct- Other	-			-
Transmission	OTPAY2	GP20	167,048	84,639	68,790	13,619	Direct- Other	-			-
Distribution	OTPAY3	GP30	1,049,436	577,126	471,954	355	Direct-MD	577,126			577,126
Payroll Taxes Salaries and Wages Adj. - Test Year									19,575	(26)	19,575
Payroll Taxes Salaries and Wages Adj. - 2023									24,612	(27)	24,612
Customer Accounts	OTPAY4	C10	391,368	255,434	135,911	23	S&W	228,896			228,896
Administrative & General	OTPAY5	O&M-AG	24,915	14,213	10,485	217	S&W	12,736			12,736
Total Payroll Taxes	TX60		1,632,767	931,413	687,140	14,215		818,758	44,187		862,945
Gross Receipts Taxes											
State Gross Receipts Taxes-MD	OTGRTMD	Direct	8,611,939	8,611,939	-	-	Direct - MD	6,955,508			6,955,508
State Gross Receipts Taxes-WV	OTGRTWV	Direct	1,957,431	-	1,957,431	-	Direct - Other	-			-
WV B&O Tax	OTB&O	Direct	4,822,789	-	4,822,789	-		-			-
Total Gross Receipts Taxes			15,392,159	8,611,939	6,780,220	-		6,955,508	-		6,955,508
Other Taxes											
Property Taxes	OTPROP	Direct	3,182	-	-	3,182		-			-
Property Taxes - MD	OTPROPMD	Direct	15,043,173	15,043,173	-	(0)	Direct- MD	13,480,260			13,480,260
Property Taxes-WV	OTPROPWV	Direct	5,278,481	-	5,278,481	(0)	Direct- Other	-			-
Property Taxes-VA	OTPROPVA	Direct	351,610	-	-	351,610	Direct- Other	-			-
Federal Excise & Federal Highway	OTFE	GP01	143	87	49	7	MDGP01	78			78
Public Utility Fuel Energy & State License	OT1	GP01	1,040	633	352	55	MDGP01	568			568
Local Contract Oblig. & Municipal Lic.	OT2	Direct	2,472	-	2,472	0	Direct- Other	-			-
Sales & Use Tax	OT3	GP01	(371,043)	(225,962)	(125,725)	(19,356)	MDGP01	(202,486)			(202,486)
Montgomery County Fuel Energy	OTMCFE	Direct	9,510,444	9,510,444	-	0	Direct - MD	9,510,444			9,510,444
MD Environmental Surcharge	OTMDENV	Direct	968,892	968,892	-	0	Direct- Other	-			-
Total Other Taxes			30,788,394	25,297,267	5,155,629	335,498		22,788,864	-		22,788,864
Total Taxes - Other			**47,813,320**	**34,840,619**	**12,622,989**	**349,712**		**30,563,131**	**44,187**		**30,607,318**
Accretion Expense	ACCR1	Direct	22,788	-	-	22,788	Direct- Other	-			-
Total Operating Expenses			**849,201,894**	**542,458,571**	**292,619,136**	**14,124,188**		**115,559,262**	**6,813,818**		**122,373,079**
Operating Income Before Tax			**99,355,485**	**58,692,106**	**51,050,186**	**(10,386,807)**		**23,283,624**	**(6,813,818)**		**16,469,806**

The Potomac Edison Company
Jurisdictional Separation Study
Maryland - Distribution
12 Months Ended December 31, 2022
In Whole Dollars

Column (1)	Reference ID (2)	Allocation Factor (3)	Total Company-Per Books (4)	Maryland (5)	West Virginia (6)	Other (7)	MD Distribution Alloc.Factor (8)	MD Distribution (9)	Going Level Adjustment (10)	Adj. No. (11)	MD Distrib. Going Level (12)
Operating Income Before Tax			**99,355,485**	**58,692,106**	**51,050,186**	**(10,386,807)**		**23,283,624**	**(6,813,818)**		**16,469,806**
Income Taxes											
Income Taxes Deferred											
Direct Assignment - MD		Direct	585,737	585,737	-	-		585,737			585,737
Direct Assignment - WV		Direct	(478,788)		(478,788)						
Plant Related		GP01	9,170,504	5,584,756	3,107,353	478,395	MDGP01	5,004,527			5,004,527
Labor Related		TX60	5,449,463	3,108,648	2,293,373	47,442	S&W	2,785,675			2,785,675
Customer Related		C10	(118,669)	(77,452)	(41,210)	(7)		(77,452)			(77,452)
Allocable Zero		Direct-Other	1,237,175	-	-	1,237,175	Direct-Other	-			-
Prior Period		Direct-Other	3,222,517	-	-	3,222,517	Direct-Other	-			-
Total Deferred Taxes - Net			19,067,939	9,201,689	4,880,728	4,985,522		8,298,486	-		8,298,486
Amortization of Investment Tax Credit		GP01	-	-	-	-	MDGP01	-			-
Income Tax Calculations											
Operating Income Before Taxes			99,355,485	58,692,106	51,050,186	(10,386,807)		23,283,624	(6,813,818)		16,469,806
Interest Charges											-
Interest Charges - Common		GP01	(29,488,167)	(17,958,032)	(9,991,833)	(1,538,301)	MDGP01	(16,092,280)			(16,092,280)
Interest Synchronization Adj.									1,974,939	(28)	1,974,939
Interest Charges - Customer Deposits			(22,016)	(17,180)	(4,837)	0	Direct- MD	(17,180)			(17,180)
Direct ABFUDC		GP01	1,667,739	1,015,638	565,100	87,001	MDCWIP	714,383			714,383
Total Interest Charges			(27,842,444)	(16,959,574)	(9,431,570)	(1,451,301)		(15,395,076)	1,974,939		(13,420,137)
Tax Deductions (Schedule M)											
Sch M Deductions-Common		GP01	(33,829,556)	(20,601,900)	(11,462,879)	(1,764,778)	MDGP01	(18,461,462)			(18,461,462)
Sch M Deductions - Labor Related		TX60	(21,336,250)	(12,171,271)	(8,979,230)	(185,749)	S&W	(10,906,735)			(10,906,735)
Sch M Customer Related (Bad Debts)		C10	437,256	285,384	151,846	26	Direct- MD	285,384			285,384
Sch M Deductions-Direct- MD		Direct - Md	(2,439,296)	(2,439,296)			Direct- MD	(2,439,296)			(2,439,296)
Sch M Deductions-Direct - WV		Direct - WV	642,012		642,012			-			
Sch M Deductions-Direct Other		Direct -other	(10,948,427)			(10,948,427)		-			
Total Tax Deductions (Schedule M's)			(67,474,261)	(34,927,083)	(19,648,250)	(12,898,927)		(31,522,110)	-		(31,522,110)
Operating Income Less Tax Modifiers			4,038,780	6,805,449	21,970,366	(24,737,035)		(23,633,563)	(4,838,879)		(28,472,441)
Adjustment to Income - WV			(268,512)		(268,512)		Direct-other	-			
Adjustment to Income - MD Bonus & Other adjustments			(10,078,439)	(10,078,439)			MDGP01	(8,141,525)			(8,141,525)
Adjustment to Income - VA Bonus & Other adjustments			(26,181,555)			(26,181,555)	Direct-other				
Adjusted State Taxable Income - WV			3,770,268		3,770,268						
Adjusted State Taxable Income - MD			(6,308,171)	(6,308,171)				(31,775,087)	(4,838,879)		(36,613,966)
Adjusted State Taxable Income - VA			(22,142,775)			(22,142,775)					
PA Income Tax			-			-					
VA Income Tax			(20,000)			(20,000)					
WV Income Tax			92,694		92,694						
MD Income Tax			(337,688)	(337,688)				(2,621,445)			(2,621,445)
State Tax NOL Reclass Expense			-								
State Tax NOL Reclass Expense-Prior			29,877			29,877					
Prior Period SIT Adj			-					-			-
State Income Taxes Adjustment									(399,207)	(29)	(399,207)
State Income Tax - Net			(235,117)	(337,688)	92,694	9,877		(2,621,445)	(399,207)		(3,020,652)

The Potomac Edison Company
Jurisdictional Separation Study
Maryland - Distribution
12 Months Ended December 31, 2022
In Whole Dollars

Column (1)	Reference ID (2)	Allocation Factor (3)	Total Company-Per Books (4)	Maryland (5)	West Virginia (6)	Other (7)	MD Distribution Alloc.Factor (8)	MD Distribution (9)	Going Level Adjustment (10)	Adj. No. (11)	MD Distrib. Going Level (12)
								-			-
Federal Taxable Income			4,035,262	(5,970,483)	3,677,574	(22,122,775)		(29,153,643)	(5,238,086)		(34,391,729)
Federal Income Tax Current			847,405	(1,253,802)	772,291	(4,645,783)		(6,122,265)		-	(6,122,265)
Federal Income Tax								-			-
Federal Income Taxes Prior & Other			218,431			218,431					-
Federal Income Tax Adjustments:								-	(932,331)	(30)	(932,331)
First Energy Service Corp Alloc.			-	-	-	-		-			-
Federal - Prior & Other Adjustments				-	-			-			-
Net Federal Income Tax			1,065,836	(1,253,802)	772,291	(4,427,352)		(6,122,265)	(932,331)		(7,054,596)
Net Utility Operating Income			**79,456,827**	**51,081,907**	**45,304,473**	**(10,954,854)**		**23,728,847**	**(5,482,279)**		**18,246,568**
Allowance For Funds Used During Construction - ABFUDC		Direct	5,790,352	3,709,703	-	2,080,649	MDCWIP	2,609,343			2,609,343
Interest on Customer Deposits		Direct	(22,016)	(17,180)	(4,837)	-	Direct- MD	(17,180)			(17,180)
Return			**85,225,162**	**54,774,430**	**45,299,636**	**(8,874,205)**		**26,321,010**	**(5,482,279)**		**20,838,731**

Column	(1)	Reference ID (2)	Allocation Factor (3)	Total Company-Per Books (4)	Maryland (5)	West Virginia (6)	Other (7)	MD Distribution Alloc.Factor (8)	MD Distribution (9)	Going Level Adjustment (10)	Adj. No. (11)	MD Distrib. Going Level (12)

ALLOCATION FACTOR DATA

Allocation Factor Description	Allocation Factor	Total Company	Maryland	WV	Other	Alloc. Factor Percentages: Total Co	MD	WV	Other
Demand at Generation Level - MWH (Retail & NonAffiliate)	D10	2,715,253	1,269,444	721,145	724,664	100.00%	46.752%	26.56%	26.689%
Average Number of Customers	C10	436,112	284,639	151,449	24	100.00%	65.267%	34.73%	0.006%

Allocation of MD Retail to MD Retail + Affil. & NonAffil. Wholesale:		**Total MD Retail and Affiliated & Nonaffiliated Wholesale**	**MD Retail**	**MD Affil. & Nonaffil. Wholesale**	**Total MD Retail and Affiliated & Nonaffiliated Wholesale**	**MD Retail**	**MD Affil. & Nonaffil. Wholesale**
Dmd at Gen. Level - kW - VA w/o FERC	Direct-JD10	1,348,179	1,269,444	78,735	100.00%	94.160%	5.84%

Allocation of MD Retail to Total Co. Retail & Affiliated Wholesale (Borderline):		**Total Co. Retail & Affiliated Wholesale**	**MD Retail**	**Other**	**Total Co. Retail & Affiliated Wholesale**	**MD Retail**	**Other**
Demand at Generation Level - kW w/o FERC	RD10	1,274,181	1,269,444	4,737	100.00%	99.628%	0.37%

Allocation of MD Retail & Affil. Wholesale(Borderline) to Total Co. Retail & Affil. Retail & Affiliated Wholesale (Borderline) and Nonaffiliated Wholesale		**Total Co. Retail & Affiliated & NonAffiliated Wholesale**	**MD Retail & Affiliated Wholesale (Borderlines)**	**Other (Including All Non-Affiliated Wholesale)**	**Total Co. Retail & Affiliated & NonAffiliated Wholesale**	**MD Retail & Affiliated Wholesale (Borderlines)**	**Other (Including All Non-Affiliated Wholesale)**
Demand at Generation Level - kW w/o FERC Nonaffil. Wholesale	RBD10	1,949,286	1,274,171	675,115	1.0000	0.65366	0.3463

Internally Calculated within Program		Total Company	Maryland	WV	Other	Alloc. Factor Percentages: Total Co	MD	WV	Other
Production Plant	GP10	0	-	-	-				
Transmission Plant	GP20	518,590,690	242,449,915	137,731,964	138,408,811	1.00	0.46752	0.27	0.26689
Distribution Plant	GP30	2,060,549,901	1,333,557,442	726,285,224	707,235	1.00	0.64719	0.35	0.00034
Transmission & Distribution Plant	GP35	2,579,140,591	1,576,007,358	864,017,187	139,116,046	1.00	0.61106	0.34	0.05394
General Plant	GP50	91,254,742	51,794,751	37,516,696	1,943,295	1.00	0.56758	0.41	0.02130
Intangible Plant	GP60	40,347,220	23,016,086	16,979,880	351,254	1.00	0.57045	0.42	0.00871
Transmission, Distribution & General Plant	GP80	2,670,395,333	1,627,802,109	901,533,883	141,059,342	1.00	0.60957	0.34	0.05282
Total Electric Plant In Service	GP01	2,710,742,554	1,650,818,195	918,513,763	141,410,596	1.00	0.60899	0.34	0.05217
Total Construction Work in Progress	L00	94,967,228	60,842,623	-	34,124,605	1.00	0.64067	-	0.35933
Total Payroll Taxes	TX60	1,632,767	931,413	687,140	14,215	1.00	0.57045	0.42	0.00871
O&M Less Fuel, Purch. Power and A&G less cust rebates	E00M	128,025,083	71,422,102	52,491,228	4,111,753	1.00	0.55788	0.41	0.03212
Total Cust. Accts/Cust.Svcs. Less MD customer rebates	E45	17,315,581	12,709,562	4,605,853	166	1.00	0.73400	0.27	0.00001
Gen & Intangible									

		Total PE S&W	Total PE Distrib. S&W	Total PE Other S&W	Total PE S&W	Alloc. Factor Percentages: Total PE Distrib. S&W Alloc.	Total PE Other S&W Alloc.
PE Salary & Wage MD Distrib. Alloc. (From PE 2022 FF1, pg. 354)	S&W	19,649,463	17,607,979	2,041,484	19,649,463	89.6105%	10.3895%

		Total MD	MD Distribution	MD Other	Total MD	MD Distrib.	MD Other
MD General Plant	MDGP50	51,794,751	46,413,528	5,381,224	1.00000	89.6105%	10.3895%
Total MD Plant to MD Distribution Plant	MDGP01	1,650,818,195	1,333,557,442	317,260,753	1.00000	80.7816%	19.2184%
MD Construction Work in Progress	MDCWIP	60,842,623	42,795,678	18,046,944.9	1.00000	70.3383%	29.6617%
Total MD Revenue to MD Distribution Revenue	MDREV	601,150,677	138,842,885	462,307,792.3	1.00000	23.0962%	76.9038%

Column (1)	Reference ID (2)	Allocation Factor (3)	Total Company-Per Books (4)	Maryland (5)	West Virginia (6)	Other (7)	MD Distribution Alloc.Factor (8)	MD Distribution (9)	Going Level Adjustment (10)	Adj. No. (11)	MD Distrib. Going Level (12)
			State Apportionment % from tax rpt 510011	Statutory State Tax Rates	Apportionment Factor * Statutory Rate						
State Tax Rates	**Effective Tax Rates**										
PA Income Tax	0.00%	VA Eff. Tax Rate	1.505%	6.000%	0.090%						
MD Income Tax	5.35%	WV ETR	37.824%	6.500%	2.459%						
VA Income Tax	0.09%										
WV Income Tax	2.46%	MD ETR	64.887%	8.250%	5.353%						
Federal Income Tax Current	21.00%	PA ETR	0.000%	0.000%	0.000%						

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

BOBBI S. MILLER

Concerning: Updated Studies for Jurisdictional and Class Cost of Service Studies

March 22, 2023

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bobbi S. Miller, and my business address is 800 Cabin Hill Drive, Greensburg, Pennsylvania 15601.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by FirstEnergy Service Company and my title is Analyst IV, Rates and Regulatory Affairs. I report to the Manager, Rates and Regulatory Affairs, and my responsibilities include assisting in the development, preparation and coordination of regulatory filings, including the studies addressed in my testimony, and the development of retail electric rates, rules, and regulations. My time is devoted to tasks performed for The Potomac Edison Company ("PE" or "Company") and Monongahela Power Company.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I am a graduate of Point Park University where I earned a Bachelor of Science degree in Legal Studies. I have over 16 years of experience with FirstEnergy Service Company or its predecessor companies and have held positions of Paralegal; Legal Specialist; Advanced Legal Specialist, and my current position of Analyst IV, Rates and Regulatory Affairs.

Q. HAVE YOU TESTIFIED IN RATE PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes, I have testified before the Public Service Commission of West Virginia.

II. PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. In Case No. 9490, the Maryland Public Service Commission ("Commission") issued an Order on March 22, 2019 that, among other items, required the Company to file updated studies for the Jurisdictional Cost of Service Study and the Class Cost of Service Study ("CCOS") such that all updated studies are current to within one year of the test year in the Company's next base rate case.[1] Listed below are the updated studies I will address in my testimony that utilized an updated test period ending 2021 and are within one year of the 2022 test year of the Company's current base rate case:

1. Customer Accounts Weighting Factor Study;
2. Meter Weighting Factor Study;
3. Minimum-Size Study; and
4. Primary/Secondary Study.

Q. HAVE YOU PREPARED OR HAD PREPARED UNDER YOUR SUPERVISION EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I am sponsoring the following Exhibits:

1. Exhibit BSM-1 - Customer Accounts Weighting Factor Study;
2. Exhibit BSM-2 – Meter Weighting Factor Study; and
3. Exhibit BSM-3 – Engineering Studies (which includes the results of the Minimum-Size Study and the Primary/Secondary Study).

[1] Ordering Paragraph (8) at 122

III. UPDATED STUDIES

Q. WHAT INFORMATION IS PROVIDED IN THE CUSTOMER ACCOUNTS WEIGHTING FACTOR STUDY AND HOW IS IT USED IN THE CCOS?

A. The Customer Accounts Weighting Factor Study, Exhibit BSM-1, analyzes Federal Energy Regulatory Commission ("FERC") Accounts 902-905, 908, 910, 450 and 451 as customer-related costs, which includes, but is not limited to, meter reading expense, customer records collection expense, uncollectible expense, and customer assistance expense, to allocate customer accounts and services expense to the various Company rate schedules in the CCOS. The source of information used and the allocation methodology for each FERC account in the study are outlined in Exhibit BSM-1.

Q. WHAT INFORMATION IS PROVIDED IN THE METER WEIGHTING FACTOR STUDY AND HOW IS IT USED IN THE CCOS?

A. The Meter Weighting Factor Study, Exhibit BSM-2, analyzes FERC Account 370 and calculates the total cost per customer for each meter, including labor cost, to allocate meter investment to the various Company rate schedules in the CCOS. To calculate the labor costs for residential customers, the study takes the average of all meter technician rates and assumes 15 minutes per installation. To calculate the labor costs for non-residential customers, the study takes the average of the meter technicians' rates for the technicians qualified to do the non-residential customer installations and assumes 60 minutes per installation.

Q. WHAT INFORMATION IS PROVIDED IN THE ENGINEERING STUDIES?

A. The Engineering Studies, Exhibit BSM-3, includes the Minimum-Size Study and the Primary/Secondary Study.

Q. WHAT IS A MINIMUM-SIZE STUDY?

A. According to the National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual, a Minimum-Size Study assumes that a minimum size distribution system can be built to serve the minimum loading requirements for the customer. The Minimum-Size Study looks at the minimum size of the assets in FERC Accounts 364 – 370, which includes, but is not limited to, poles, conductors, transformers, conduit, and service, that will be needed to build the minimum size distribution system. Once that is determined, the minimum size distribution system is classified as customer-related costs. The difference between customer-related costs and total investment in that specific FERC account is then classified as demand-related costs. The source of information used and the allocation methodology for each FERC account in the study is outlined in Exhibit BSM-3.

Q. WHY DID THE COMPANY PERFORM A MINIMUM-SIZE STUDY?

A. The Company performed a Minimum-Size Study and Company witness Lyons performed a Zero-Intercept Study. FirstEnergy Corporation has developed internal tools to streamline performance of a Minimum-Size Study based on previous rate case studies in other states in which it has operations. The Minimum-Size Study method was performed to leverage the existing tools that work with the Company's database structure to reduce the time and effort needed to complete the portion of the study that establishes the customer versus demand portion of FERC Accounts 364-370. Company witness Lyons will discuss the

Zero-Intercept Study and how that study is ultimately utilized in the CCOS in his direct testimony.

Q. WHAT IS A PRIMARY/SECONDARY STUDY?

A. The Primary/Secondary Study analyzes FERC Accounts 364-367, which includes, but is not limited to, poles, conductors, and transformers, to determine the Company's assets used to serve primary voltage customers from the customer-related costs of the Minimum-Size Study. The remaining assets are then allocated to secondary customers. The source of information used and the allocation methodology for each FERC account in the study is outlined in Exhibit BSM-3.

Q. WHAT IS A POLE SAMPLE/STREETLIGHTING STUDY AND WHY DID THE COMPANY NOT INCLUDE THIS AS A SEPARATE STUDY IN ITS FILING?

A. The Pole Sample/Streetlighting Study sub-functionalizes the poles in FERC Accounts 360, 364, and 365 amongst the various voltage levels, and breaks out street lighting dedicated poles, which determines the ratio of poles dedicated to primary versus secondary versus street lighting service. This study has been incorporated into the Primary/Secondary Study listed above, so there is not a separate study that addresses the sub-functionalization of the poles into primary/secondary/streetlighting customers.

Q. WERE ALL THE PREVIOUSLY DISCUSSED STUDIES UPDATED TO WITHIN ONE YEAR OF THE 2022 TEST YEAR OF THE COMPANY'S BASE RATE CASE?

A. Yes.

Q. IS THERE ANY ADDITIONAL DATA THE COMMISSION REQUIRED THE COMPANY TO ADDRESS IN THIS RATE CASE?

A. Yes, in its March 22, 2019 Order, the Commission required the Company to file: (1) testimony supporting or rejecting the use of the Average Coincident Peak methodology to allocate costs related to subtransmission and FERC Accounts 362 and 368 capacitors based on current system conditions and cost causation; (2) three years of demand at transmission, subtransmission, primary, and secondary levels, as well as their resulting allocators that are used in the CCOS; and (3) to file a CCOS with and without a Zero-Intercept Study being utilized in the CCOS' allocations.

Q. HAS THE COMPANY ADDRESSED THESE ADDITIONAL REQUIREMENTS?

A. Yes, these items are addressed in the Direct Testimony of Company witness Lyons.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

The Potomac Edison Company

Exhibit BSM-1

Customer Account Weighting Factor Study

The Potomac Edison Company

Year Ending December 2021

<u>FERC 902 Meter Reading Expenses</u>

Overview

The allocation methodology required a two-step process. First, a weighting factor was calculated for each rate class based on the number of meters in that rate class and the read time for those meters. Then, these weight factors were used to determine the allocation of the FERC balance across the rate classes.

Source of Data

FERC 902 account balance for 2021.

Normalized billing units were used for the number of customers at December 2021 (end of period).

Read times for each meter by rate class were obtained from Customer Service Analytics. Streetlights were excluded from the calculations as a majority of those accounts are not metered.

Allocation Methodology

- The December 2021 (end of period) Number of Customers (a) for each rate category is based on the Normalized billing units.
- The weighted factor (b) is based on the read time for each rate category and represents the minutes per meter to obtain a reading.
- The Weighted Customer Count (c) is the Customer Count (a) X Weighted factor (b).
- Total $ by Rate (d) was calculated by taking the Weighted Customer Count by rate class (c) divided by Total Weighted Customer Count X Total FERC Balance equals FERC balance by rate class.

Customers By Rate Class	December 2021 Number Customers (a)	Weighted Factor (b)	Weighted Customer Count (c) = (a) * (b)	Total $ by Rate (d)
Residential				
R - Residential	374,991	1.09	408,740	$4,671,181
Total Residential	**374,991**		**408,740**	**$4,671,181**
Commercial				
G - General Service	39,235	1.46	57,283	$654,645
C - General	4,001	1.52	6,082	$69,501
CSH - Church and School	223	2.11	471	$5,377
C-A - All Electric	304	2.11	641	$7,331
E - General Service	3,548	1.54	5,464	$62,443
PH - Light & Power	1,422	2.61	3,711	$42,415
Total Commercial	**48,733**		**73,652**	**$841,712**
Industrial				
G - General Service	3,159	2.04	6,444	$73,648
E - General Service	482	2.31	1,113	$12,724
C - General	451	2.08	938	$10,721
C-A - All Electric	33	3.20	106	$1,207
PH - Light & Power	306	3.04	930	$10,631
Total Industrial	**4,431**		**9,532**	**$108,931**
Public St & Highway Lighting				
Public St & Highway Lighting	614			
Total Public St & Highway Lighting	**614**			
Total	**428,769**		**491,924**	**$5,621,823**

FERC 903 Customer Records Collection Expenses

Overview

The normalized billing units were used for the number of customers at December 2021 (end of period) to calculate a weighted distribution of the FERC 903 account balance.

Source of Data

FERC 903 account balance for 2021

Normalized billing units were used for the number of customers at December 2021 (end of period).

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate class was calculated based on the normalized billing units (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 903 balance to determine the distribution of dollars across the rate classes (c).

Title of Rate Schedule	December 2021 Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
R - Residential	374,991	0.8746	$4,188,558
Total Residential	**374,991**	**0.8746**	**$4,188,558**
Commercial			
G - General Service	39,235	0.0915	$438,245
C - General	4,001	0.0093	$44,690
CSH - Church and School	223	0.0005	$2,491
C-A - All Electric	304	0.0007	$3,396
E - General Service	3,548	0.0083	$39,630
PH - Light & Power	1,422	0.0033	$15,883
Total Commercial	**48,733**	**0.1137**	**$544,336**
Industrial			
G - General Service	3,159	0.0074	$35,285
E - General Service	482	0.0011	$5,384
C - General	451	0.0011	$5,038
C-A - All Electric	33	0.0001	$369
PH - Light & Power	306	0.0007	$3,418
Total Industrial	**4,431**	**0.0103**	**$49,493**
Public St & Highway Lighting			
Public St & Highway Lighting	614	0.0014	$6,858
Total Public St & Highway Lighting	**614**	**0.0014**	**$6,858**
Total	**428,769**		**$4,789,245**

FERC 904 Uncollectible Accounts

Overview

The normalized billing units were used for the number of customers at December 2021 (end of period) to calculate a weighted distribution of the FERC 904 account balance.

Source of Data

FERC 904 account balance for 2021

Normalized billing units were used for the number of customers at December 2021 (end of period).

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the normalized billing units (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 904 balance to determine the distribution of dollars across the rate classes (c).

Title of Rate Schedule	December 2021 Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
R - Residential	374,991	0.8746	$162,616
Total Residential	**374,991**	**0.8746**	**$162,616**
Commercial			
G - General Service	39,235	0.0915	$17,014
C - General	4,001	0.0093	$1,735
CSH - Church and School	223	0.0005	$97
C-A - All Electric	304	0.0007	$132
E - General Service	3,548	0.0083	$1,539
PH - Light & Power	1,422	0.0033	$617
Total Commercial	**48,733**	**0.1137**	**$21,133**
Industrial			
G - General Service	3,159	0.0074	$1,370
E - General Service	482	0.0011	$209
C - General	451	0.0011	$196
C-A - All Electric	33	0.0001	$14
PH - Light & Power	306	0.0007	$133
Total Industrial	**4,431**	**0.0103**	**$1,922**
Public St & Highway Lighting			
Public St & Highway Lighting	614	0.0014	$266
Total Public St & Highway Lighting	**614**	**0.0014**	**$266**
Total	**428,769**		**$185,937**

<u>FERC 905 Miscellaneous Customer Accounts Expenses</u>

Overview

The normalized billing units were used for the number of customers at December 2021 (end of period) to calculate a weighted distribution of the FERC 905 account balance.

Source of Data

FERC 905 account balance for 2021

Normalized billing units were used for the number of customers at December 2021 (end of period).

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the normalized billing units (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 905 balance to determine the distribution of dollars across the rate classes (c).

Title of Rate Schedule	December 2021 Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
R - Residential	374,991	0.8746	$458,726
Total Residential	**374,991**	**0.8746**	**$458,726**
Commercial			
G - General Service	39,235	0.0915	$47,996
C - General	4,001	0.0093	$4,894
CSH - Church and School	223	0.0005	$273
C-A - All Electric	304	0.0007	$372
E - General Service	3,548	0.0083	$4,340
PH - Light & Power	1,422	0.0033	$1,740
Total Commercial	**48,733**	**0.1137**	**$59,615**
Industrial			
G - General Service	3,159	0.0074	$3,864
E - General Service	482	0.0011	$590
C - General	451	0.0011	$552
C-A - All Electric	33	0.0001	$40
PH - Light & Power	306	0.0007	$374
Total Industrial	**4,431**	**0.0103**	**$5,420**
Public St & Highway Lighting			
Public St & Highway Lighting	614	0.0014	$751
Total Public St & Highway Lighting	**614**	**0.0014**	**$751**
Total	**428,769**		**$524,512**

<u>FERC 450 & 451 Forfeited Discounts and Miscellaneous Service Revenues</u>

Overview

The normalized billing units were used for the number of customers at December 2021 (end of period) to calculate a weighted distribution of the FERC 450 and 451 expenses.

Source of Data

FERC 450 and 451 account balance for 2021

Normalized billing units were used for the number of customers at December 2021 (end of period).

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the normalized billing units (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 450 and 451 balance to determine the distribution of dollars across the rate classes (c).

Title of Rate Schedule	December 2021 Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
R - Residential	374,991	0.8746	-$2,655,425
Total Residential	**374,991**	**0.8746**	**-$2,655,425**
Commercial			
G - General Service	39,235	0.0915	-$277,835
C - General	4,001	0.0093	-$28,332
CSH - Church and School	223	0.0005	-$1,579
C-A - All Electric	304	0.0007	-$2,153
E - General Service	3,548	0.0083	-$25,124
PH - Light & Power	1,422	0.0033	-$10,070
Total Commercial	**48,733**	**0.1137**	**-$345,093**
Industrial			
G - General Service	3,159	0.0074	-$22,370
E - General Service	482	0.0011	-$3,413
C - General	451	0.0011	-$3,194
C-A - All Electric	33	0.0001	-$234
PH - Light & Power	306	0.0007	-$2,167
Total Industrial	**4,431**	**0.0103**	**-$31,377**
Public St & Highway Lighting			
Public St & Highway Lighting	614	0.0014	-$4,348
Total Public St & Highway Lighting	**614**	**0.0014**	**-$4,348**
Total	**428,769**		**-$3,036,243**

FERC 908 Customer Assistance Expenses

Overview

The FERC 908 account balance for 2021 was assigned to Rate RS because it is the only rate schedule on which the customers receiving service participate in the Company's customer assistance programs.

Source of Data

FERC 908 account balance for 2021

Allocation Methodology

The FERC 908 account balance was assigned to RS Rate (a)

Company	Balance	RS Balance (a)
Potomac Edison	$107,369	$107,369

FERC 910 Miscellaneous Customer Service and Information Expenses

Overview

FERC 910 account balances were distributed based on actual call volume for 2021. Ratios for rate class call volumes were calculated based on call volume and the normalized billing units were used for the number of customers and then applied to the total FERC balance to distribute the dollars across the rate classes.

Source of Data

FERC 910 account balance for 2021

Normalized billing units were used for the number of customers at December 2021 (end of period).

Call Volumes from the IVR Calls by Call Report for 2021

Allocation Methodology

Cost Allocations by Call Category were performed by multiplying the FERC Form 910 Costs by the Percentage of Calls in each category (Residential, Commercial & Industrial, and Streetlight) compared to the total Call Volume. Because commercial and industrial calls cannot be broken out by customer class, a percentage was calculated for the commercial and for the industrial classes based on normalized billing units- the number of customers at December 2021 (end of period). These percentages were then used to allocate costs to each of the categories.

Calls by Customer Category	Count	Percentage	$
Residential	444,293	92.05%	$2,771,090
Commercial & Industrial	35,662	7.39%	$222,427
Commercial (Based on Customer Count) [1]	*32,690*	6.77%	$203,888
Industrial (Based on Customer Count) [2]	*2,972*	0.62%	$18,538
Public St & Highway Lighting	2,724	0.56%	$16,990
Total Calls	**482,679**	**100.00%**	**$3,010,507**

[1]Commercial (Based on Customer Count) = Total Commercial Customers/Total Commercial & Industrial Customers

[2]Industrial (Based on Customer Count) = Total Industrial Customers / Total Commercial & Industrial Customers

To calculate the distribution of dollars across the rate classes (c) the percentage of customers in each rate category was calculated (b) based on the normalized billing units (a). This percentage was then multiplied by the dollars allocated to each Call Category (Residential, Commercial, Industrial, and Streetlight), as calculated above, to determine the dollars by rate class.

Customers By Rate Class	December 2021 Number Customers (a)	Percentage (b)	Total $ by Rate (c)
Residential			
R - Residential	374,991	100.00%	$2,771,090
Total Residential	**374,991**	**100.00%**	**$2,771,090**
Commercial			
G - General Service	39,235	80.51%	$164,151
C - General	4,001	8.21%	$16,739
CSH - Church and School	223	0.46%	$933
C-A - All Electric	304	0.62%	$1,272
E - General Service	3,548	7.28%	$14,844
PH - Light & Power	1,422	2.92%	$5,949
Total Commercial	**48,733**	**100.00%**	**$203,888**
Industrial			
G - General Service	3,159	71.29%	$13,217
E - General Service	482	10.88%	$2,017
C - General	451	10.18%	$1,887
C-A - All Electric	33	0.74%	$138
PH - Light & Power	306	6.91%	$1,280
Total Industrial	**4,431**	**100.00%**	**$18,538**
Total Commercial & Industrial	**53,164**		
Public St & Highway Lighting			
Public St & Highway Lighting	614	100.00%	$16,990
Total Public St & Highway Lighting	**614**	**100.00%**	**$16,990**
Total	**428,769**		**$3,010,507**

Summary Chart

Potomac Edison Customer Accounting Total Account Dollars Assigned to Rate Group							
Rate	Meter Reading	Customer Records Collection	Uncollectible Accounts	Miscellaneous Customer Accounts	Forfeited Discounts and Miscellaneous Service Revenues	Cust Asst	MISC
Classes	**902**	**903**	**904**	**905**	**450 & 451**	**908**	**910**
Residential							
R - Residential	$4,671,181	$4,188,558	$162,616	$458,726	($2,655,425)	$107,369	$2,771,090
Total Residential	**$4,671,181**	**$4,188,558**	**$162,616**	**$458,726**	**($2,655,425)**	**$107,369**	**$2,771,090**
Commercial							
G - General Service	$654,645	$438,245	$17,014	$47,996	($277,835)	-	$164,151
C - General	$69,501	$44,690	$1,735	$4,894	($28,332)	-	$16,739
CSH - Church and School	$5,377	$2,491	$97	$273	($1,579)	-	$933
C-A - All Electric	$7,331	$3,396	$132	$372	($2,153)		$1,272
E - General Service	$62,443	$39,630	$1,539	$4,340	($25,124)	-	$14,844
PH - Light & Power	$42,415	$15,883	$617	$1,740	($10,070)	-	$5,949
Total Commercial	**$841,712**	**$544,336**	**$21,133**	**$59,615**	**($345,093)**	**$0**	**$203,888**
Industrial							
G - General Service	$73,648	$35,285	$1,370	$3,864	($22,370)		$13,217
E - General Service	$12,724	$5,384	$209	$590	($3,413)		$2,017
C - General	$10,721	$5,038	$196	$552	($3,194)	-	$1,887
C-A - All Electric	$1,207	$369	$14	$40	($234)	-	$138
PH - Light & Power	$10,631	$3,418	$133	$374	($2,167)	-	$1,280
Total Industrial	**$108,931**	**$49,493**	**$1,922**	**$5,420**	**($31,377)**	**$0**	**$18,538**
Public St & Highway Lighting							
Public St & Highway Lighting	$0	$6,858	$266	$751	($4,348)	-	$16,990
Total Public St & Highway Lighting	**$0**	**$6,858**	**$266**	**$751**	**($4,348)**	**$0**	**$16,990**
Total	**$5,621,823**	**$4,789,245**	**$185,937**	**$524,512**	**($3,036,243)**	**$107,369**	**$3,010,507**

The Potomac Edison Company

Exhibit BSM-2

Meter Weighting Factor Study

Detailed calculation of total cost per customer used to develop the weighting factors and weighted customer allocator:

COS RATE GROUP	END OF PERIOD HTY CUSTOMER COUNT	METER COUNT	METER COST	METER LABOR	PT/CT COST & LABOR	TOTAL COST	AVERAGE TOTAL COST PER METER	AVERAGE TOTAL COST PER CUSTOMER	WEIGHTING FACTOR (CUSTOMER)	WEIGHTED CUSTOMER ALLOCATOR	WEIGHTING FACTOR (METER)	WEIGHTED METER ALLOCATOR
[A]	[B]	[C]	[D]	[E]	[F]	[G] = [D+E+F]	[H]=[G/C]	[I]=[G/B]	[J] = [I/min(I)]	[K]=[B*J]	[L]=[H/min(H)]	[M]=[C*L]
R	247,033	250,988	$ 6,165,755	$ 3,464,610	$ 83,984	$ 9,714,349	$ 39	$ 39	100%	247,033	100%	250,988
G	26,419	27,161	$ 1,328,106	$ 353,197	$ 2,363,593	$ 4,044,895	$ 149	$ 153	389%	102,860	385%	104,507
C	4,447	4,303	$ 184,779	$ 70,038	$ 301,230	$ 556,047	$ 129	$ 125	318%	14,140	334%	14,366
CA	218	210	$ 15,689	$ 5,673	$ 38,238	$ 59,600	$ 284	$ 273	695%	1,516	733%	1,540
CSH	118	117	$ 10,219	$ 4,042	$ 27,728	$ 41,989	$ 359	$ 356	905%	1,068	927%	1,085
PH	1,673	1,727	$ 382,772	$ 32,403	$ 1,228,396	$ 1,643,572	$ 952	$ 982	2498%	41,796	2459%	42,465
PPD	10	14	$ 7,288	$ 612	$ 265,929	$ 273,830	$ 19,559	$ 27,383	69634%	6,963	50535%	7,075
HAGFRE	39	37	$ 1,048	$ 645	$ 1,833	$ 3,526	$ 95	$ 90	230%	90	246%	91
MAN	1	2	$ 5,001	$ 122	$ 12,677	$ 17,800	$ 8,900	$ 17,800	45264%	453	22994%	460
WSDV	19	18	$ 2,884	$ 810	$ 39,841	$ 43,534	$ 2,419	$ 2,291	5827%	1,107	6249%	1,125
FE-	27	35	$ 6,828	$ 2,846	$ 120,062	$ 129,736	$ 3,707	$ 4,805	12219%	3,299	9577%	3,352

The Potomac Edison Company

Exhibit BSM-3

Engineering Studies

[Minimum-Size Study and Primary/Secondary Study]

EXHIBIT BSM-3

Customer Component of

FERC Account 364 – POLES, TOWERS, AND FIXTURES

FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES

FERC Account 367 – UNDERGROUND CONDUCTORS & DEVICES

FERC Account 368 – LINE TRANSFORMERS

Primary Customer/Secondary Customer Component of

FERC Account 364 – POLES, TOWERS, AND FIXTURES

FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES

FERC Account 366 – UNDERGROUND CONDUIT

FERC Account 367 – UNDERGROUND CONDUCTORS & DEVICES

Streetlight Component of

FERC Account 364 – POLES, TOWERS, AND FIXTURES

Overhead & Underground Component of

FERC Account 368 – LINE TRANSFORMERS

FERC Account 369 – SERVICES

Table of Contents

SCOPE

This report looks at two concepts, the allocation of certain distribution plant accounts to a customer cost (aka "minimum grid") or demand costs, here after referred to as the Customer Cost Study, and the allocation of certain distribution costs to customers served as primary voltage accounts. NARUC describes the basics of Customer Costs Studies in their publication "Electric Utility Cost Allocation Manual[1]," but the basics of these studies are to serve the purpose of allocating utility costs and/or asset values to different classes of customers.

Customer Cost Study

The Customer Cost Study is designed to separate the asset values into component costs, as follows:

- Customer Related Costs
- Demand Related Costs
- Energy Related Costs

The costs of the distribution system are primarily impacted by demand and the number of customers, so this study serves the purpose of allocating utility costs and/or asset values to those two cost components[2]. The plant accounts considered in this study are:

- FERC Account 364 – POLES, TOWERS, AND FIXTURES
- FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES
- FERC Account 367 – UNDERGROUND C ONDUCTORS & DEVICES
- FERC Account 368 – LINE TRANSFORMERS

Primary/Secondary Customer Cost Study

The primary/secondary customer cost study is aimed at determining the portion of the distribution assets that are used to serve primary voltage customers; for example, the distribution transformer, secondary conductor, and service conductor types of distribution plant are not used to serve these customers. Similarly, some accounts have limited assets that are used to provide service to these primary service customers; the Primary/Secondary Customer Cost Study is designed to determine the extent of each of those accounts used by the Primary Voltage Customer[3]. The accounts considered in this study are:

- FERC Account 364 – POLES, TOWERS, AND FIXTURES
- FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES

[1] National Association of Regulatory Utility Commissions (NARUC). *Electric Utility Cost Allocation Manual*, 1992.

[2] ibid, p. 21.

[3] ibid, p. 19.

- FERC Account 366 – UNDERGROUND CONDUIT
- FERC Account 367 – UNDERGROUND CONDUCTORS & DEVICES

DEFINTIONS AND TERMS

Several large data bases house the information used in the preparation of this report. The following definitions and terms describe: those systems and applications, from which data was extracted; the software tools used to extract, analyze, and summarize that information; and finally, references are provided to any external data sources used.

Company Computer Systems, Data and Processes

The Company has several computer systems that house data used for this study. As utilities have grown, so has the size and complexity of these systems leading to the need to use software tools like SQL queries to analyze data sets that can no-longer be effectively analyzed using common desktop tools like Excel.

CCS

The Company's CCS or "Customer Care System" is the customer accounting and billing system. With data contained in this system the Company is able to tell the type of customer, the customer's customer rate code. The GIS and CCS customer records are connected though connection object database keys, which enable the Company to determine where, on the geographically represented system, each customer, and customer type, is connected. The CCS is a sub-system of SAP (see SAP below).

CREWS

CREWS is FirstEnergy's work management system, used by the Operating Companies to perform engineering estimates for construction work.

GIS

The Company's GIS or "Geographical Information System" is the computer system providing a geographically referenced, asset database of the installed distribution plant information, including information on poles, primary conductors, fuses, transformers, and switches, and how those pieces of the electric distribution system are electrically interconnected from the substation to the customer. The GIS is used primarily for mapping and detailing the distribution system aiding engineering design, planning, and troubleshooting tasks.

SAP

SAP[4] offers bundles of applications and services to enable companies to manage their businesses. These applications can include customer care systems (CCS), billing, financial, purchasing, inventory, and human resources functions.

Software Tools

SQL

Structured Query Language (SQL)[5] is a special programming language designed to manage and extract data held in a relational data base management system (RDBS), like Oracle, Sybase, MySQL, or, Microsoft SQL Server. Most of the Company's data bases, used for the preparation of this report, are Oracle RDBSs.

Toad Data Point

Toad Data Point, by Quest Software Inc[6], a cross-platform, self-service, data-integration tool that simplifies data access, preparation, and provisioning. FirstEnergy uses Toad Data Point for general SQL execution and Data Cleaning as it pertains to studies on large datasets.

Microsoft Excel

Excel, by Microsoft[7], is a general use spreadsheet application. The software has functions allowing calculations, graphing, and aggregating data through use of pivot tables.

External Data Sources

Handy-Whitman Index

The *Handy-Whitman Index of Public Utility Construction*[8] provides asset price indexes and the capital book value against a benchmark year. Handy-Whitman Index numbers serve as a yardstick to estimate the impact of fluctuations in the value of material and labor costs, allowing assets of a known age to be reflected in other years. Average prices and cost trends are used to develop the Handy-Whitman Index. This Index is commonly used by utilities and regulators in their calculations of rate base for rate cases and in their valuations of property for insurance purposes.

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[4] SAP, www.sap.com.

[5] ISO/IEC 9075-1:2011, *Information technology -- Database languages -- SQL -- Part 1: Framework (SQL/Framework)*,

[6] Quest Software, https://www.quest.com/.

[7] Microsoft,www.microsoft.com.

[8] *Handy-Whitman Index of Public Utility Construction*, Whitman, Requardt and Associates, LLP, 801 South Caroline Street, Baltimore, MD 21231,

Electric Utility Cost Allocation Manual[9]

The Electric Utility Cost Allocation Manual, by NARUC**,** was written by a team of utility, public utility commission, and FERC representatives and provides frameworks for costs of service studies. Section II of this Manual contains five chapters that explain the dominant method of cost allocation - the embedded cost study, which is based upon historical or known utility costs. Areas covered are production costs, transmission costs, distribution costs and the classification and allocation of customer-related costs and investments.

[9] National Association of Regulatory Utility Commissions (NARUC). *Electric Utility Cost Allocation Manual*, 1992.

Customer Component of

FERC Account 364 – POLES, TOWERS, AND FIXTURES

FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES

FERC Account 367 – UNDERGROUND CONDUCTORS & DEVICES

FERC Account 368 – LINE TRANSFORMERS

FERC Account 364 – POLES, TOWERS, AND FIXTURES

This plant distribution account is predominately made up of the various wood distribution poles used to support primary and secondary distribution conductors.

Assumptions and Method

- The Company's GIS was used to determine the number of wood distribution poles, by size and install year. In the analysis, these poles were replaced by the minimum size wood distribution poles that have seen common use within the study territory; 35-foot poles for those supporting primary conductors without joint use underbuild.
  - Poles without an install year were omitted
  - Poles with install years < 1912 were omitted
  - Only poles supporting primary conductor were included (i.e., street-light and secondary only poles were omitted).
  - Only poles where POLE_MAT in (D, L, M, N, P, R, W, Z) were considered … the other materials are fiberglass, steel, concrete, aluminum, etc. materials that are unlikely for "distribution" poles.
  - Only poles where HEIGHT in (25, 30, 35, 40, 45, 50, 55, 60, 65, 70, 75, 80, 85, 90, & 95) were considered, the other pole heights typically indicate either street-light only poles, i.e., HEIGHT in (12, 15, 16, 17, 20, 27) or may reflect erroneous data.
- The current installed cost for each size pole was obtained from CREWS and trended by size to build a list of costs by pole length for each size wood pole.
- The install years were used to age the current costs for the actual size and minimum size transformers using Handy-Whitman indices and extended by the number of poles in service for each year, then summed to develop the customer component for this plant account.
- The percentage of minimum size cost (Customer Cost), of the Total Plant Value was calculated as the portion represented by the cost of the minimum sized units, 35-foot poles, as previously defined. The percentage of the demand costs for the account is the remainder, after the customer cost component was removed.
- The methodology, approach, and assumptions for performing the primary rate customer split of this FERC Account (FERC Form 1 Plant Account 364) is described in more detail later in this document. The Minimum Grid aspect of the primary rate customer portion and secondary rate customer portion is summarized below.

FERC Account 364 POLES, TOWERS, AND FIXTURES SPLIT OF PLANT					
Company	Total Plant Value	Customer Costs		Demand Costs	
		Percent	Value	Percent	Value
Potomac Edison Maryland	$128,631,437[10]	80.3%	$103,273,689	19.7%	$25,357,748
Potomac Edison Maryland – Primary Customers	$7,070,016	65.7%	$4,643,191	34.3%	$2,426,826
Potomac Edison Maryland – Secondary Customers	$121,561,421	81.1%	$98,630,499	18.9%	$22,930,922

[10] Per The Potomac Edison Company - MD, FERC Form No. 1, Year/Period of Report, End of 2021/Q4, Account 364, Balance at End of Year, pg. 206.

FERC Account 365 - OVERHEAD CONDUCTORS AND DEVICES

This plant distribution account is predominately made up of the various overhead distribution line conductors, operating at either primary or secondary voltage. This study considered primary conductors only, the Company's GIS data is not sufficient to perform a similar analysis on the costs of secondary, service, and/or street-light conductors. The Company's GIS data is not sufficient to perform a Handy-Whitman analysis of the install date for primary conductors.

Assumptions and Method

- The Company's GIS was used to determine the wire miles of overhead distribution primary distribution line conductors, by size. These conductors were categorized into two sizes, large and small.
    - Conductors with a blank or unknown conductor type/size were omitted.
    - Conductor segments longer than 700 feet were omitted as likely being in error or non-representative of typical distribution construction.
- The current installed cost for each category of primary line conductor was obtained and used to cost out the currently installed system, if rebuilt using one of those two sizes.
- The minimum grid cost was developed using only the cost of the smaller conductor.
- The percentage of minimum size cost (Customer Cost), of the Total Plant Value was calculated as the portion represented by the cost of the system, built with the minimum sized conductor.
- The methodology, approach, and assumptions for performing the primary rate customer split of this FERC Account (FERC Form 1 Plant Account 365) is described in more detail later in this document. The Minimum Grid aspect of the primary rate customer portion and secondary rate customer portion is summarized below.

FERC Account 365 OVERHEAD CONDUCTORS AND DEVICES SPLIT OF PLANT					
Company	Total Plant Value	Customer Costs		Demand Costs	
		Percent	Value	Percent	Value
Potomac Edison Maryland	$226,243,593[11]	95.8%	$216,704,339	4.2%	$9,539,254
Potomac Edison Maryland – Primary Customers	$12,061,858	87.1%	$10,501,142	12.9%	$1,560,716
Potomac Edison Maryland – Secondary Customers	$214,181,735	96.3%	$206,203,196	3.7%	$7,978,539

[11] Per The Potomac Edison Company - MD, FERC Form No. 1, Year/Period of Report, End of 2021/Q4, Account 365, Balance at End of Year, pg. 206.

FERC Account 367 - UNDERGROUND CONDUCTORS AND DEVICES

This plant distribution account is predominately made up of the various underground distribution line conductors, operating at either primary or secondary voltage. This study considered primary conductors only, the Company's GIS data is not sufficient to perform a similar analysis on the costs of secondary and/or service conductors.

Assumptions and Method

- The Company's GIS was used to determine the wire miles of underground distribution primary distribution line conductors, by size. These conductors were categorized into two sizes, large and small.
  - Conductors with a blank or unknown conductor type/size were omitted
  - Conductor segments greater than 2,500' were considered data errors and omitted
- The current installed cost for each category of primary line conductor was obtained and used to cost out the currently installed system, if rebuilt using one of those two sizes.
- The minimum grid cost was developed using only the cost of the smaller conductor.
- The percentage of minimum size cost (Customer Cost), of the Total Plan Value was calculated as the portion represented by the cost of the system, built with the minimum sized conductor.
- The methodology, approach, and assumptions for performing the primary rate customer split of this FERC Account (FERC Form 1 Plant Account 367) is described in more detail later in this document. The Minimum Grid aspect of the primary rate customer portion and secondary rate customer portion is summarized below.

FERC Account 367 UNDERGROUND CONDUCTORS AND DEVICES SPLIT OF PLANT					
Company	Total Plant Value	Customer Costs		Demand Costs	
		Percent	Value	Percent	Value
Potomac Edison Maryland	$295,149,931[12]	84.3%	$248,740,541	15.7%	$46,409,390
Potomac Edison Maryland – Primary Customers	$6,437,659	59.3%	$3,814,404	40.7%	$2,623,255
Potomac Edison Maryland – Secondary Customers	$288,712,272	84.8%	$244,926,137	15.2%	$43,786,135

[12] Per The Potomac Edison Company - MD, FERC Form No. 1, Year/Period of Report, End of 2021/Q4, Account 367, Balance at End of Year, pg. 206.

FERC Account 368 - LINE TRANSFORMERS

This plant distribution account is predominately made up of the various distribution transformers used to step the distribution voltage down to the service-voltage level delivered to the customer. This account includes both overhead and pad-mounted transformers.

Assumptions and Method

- The Company's GIS system was used to determine the number of overhead and pad-mounted distribution transformers, by size and install year, to be replaced by the minimum size (25 KVA Single Phase) overhead line transformer that is in common use within the study territory.
- The current installed cost for each size line transformer was obtained from CREWS and trended by size to build a list of costs by size for each size overhead and pad-mounted distribution transformer.
- The install years were used to age the current costs for the actual size and minimum size transformers using Handy-Whitman indices and extended by the number of transformers in service for each year, then summed to develop the customer component for this plant account.
- Transformers missing install year, construction type, or kVA were omitted.
- The percentage of minimum size cost, of the calculated current cost was calculated as the portion represented by the cost of the minimum sized units.
- The methodology, approach, and assumptions for performing the primary rate customer split of this FERC Account (FERC Form 1 Plant Account 368) is described in more detail later in this document. The Minimum Grid aspect of the primary rate customer portion and secondary rate customer portion is summarized below.
- Overhead (OH) minimum grid is 100% assigned for secondary rate customers due to a large number of existing transformers on the system being at or less than 25kVA.

FERC Account 368 LINE TRANSFOMERS SPLIT OF PLANT					
Company	Total Plant Value	Customer Costs		Demand Costs	
		Percent	Value	Percent	Value
Potomac Edison Maryland	$201,703,535[13]	56.0%	$112,942,090	44.0%	$88,761,445
Potomac Edison Maryland – Primary Customers	$336,829	22.0%	$74,063	78.0%	$262,766
Potomac Edison Maryland – Secondary Customers	$201,366,706	56.1%	$112,868,026	43.9%	$88,498,680
Potomac Edison Maryland – OH Transformer Secondary Customers	$83,275,299	100.0%	$83,275,299	0.0%	$0
Potomac Edison Maryland – UG Transformer Secondary Customers	$118,091,407	42.6%	$50,347,505	57.4%	$67,743,902

[13] Per The Potomac Edison Company - MD, FERC Form No. 1, Year/Period of Report, End of 2021/Q4, Account 368, Balance at End of Year, pg. 206.

Primary Customer/Secondary Customer Component of

FERC Account 364 – POLES, TOWERS, AND FIXTURES

FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES

FERC Account 366 – UNDERGROUND CONDUIT

FERC Account 367 – UNDERGROUND CONDUCTORS & DEVICES

FERC Account 364 – POLES, TOWERS, AND FIXTURES

This plant distribution account is predominately made up of the various wood distribution poles used to support primary and secondary distribution conductors.

Assumptions and Method

Using data from the Company's GIS, the wood pole plant was separated by poles which have both primary and secondary attached facilities, poles with secondary attached facilities, poles with secondary attached facilities and wood poles with street-lighting facilities. To divide up the value of the account, an age-depreciated weighting based upon the cost to install a pole in today's dollars (Year 2022) was used consistent with the minimum grid portion of the analysis.

The Company's pole data allows for the identification of the total wood poles plant, and wood poles with primary facilities attached, but does not allow for the identification of poles with private-outdoor lighting facilities, street-light facilities or secondary facilities. The poles serving primary service customers are allocated to primary rate customers, all other poles will need to be split between all rate classes, except primary service customers.

A list of primary rate accounts was extracted from the CCS and used as the starting point for traces in the GIS system. From these traces in GIS, for each of the primary accounts and their associated Connection Object were reviewed to determine if multiple primary customers shared primary circuit routes to ensure facilities allocated to primary rate customers were only counted once.

- Only poles supporting primary and secondary conductor were included (i.e., street-light only poles were omitted).
- Only poles where POLE_MAT in (D, L, M, N, P, R, W, Z) were considered … the other materials are fiberglass, steel, concrete, aluminum, etc. materials that are unlikely for "distribution" poles.
- Only poles where HEIGHT in (15, 20, 25, 30, 35, 40, 45, 50, 55, 60, 65, 70, 75, 80, 85, 90, & 95) were considered, the other pole heights typically indicate either street-light only poles, i.e., HEIGHT in (12, 15, 16, 17, 20, 27) or may reflect erroneous data.

FERC Account 364 **POLES, TOWERS, AND FIXTURES** **SPLIT OF PLANT**					
Company	Total Plant Value	Primary Customers		Secondary and Street Light Customers	
		Percent	Value	Percent	Value
Potomac Edison Maryland	$128,631,437[14]	5.5%	$7,070,016	94.5%	$121,561,421

When a device or structure serves multiple primary customers, it is only counted one time in the results. See Figure 1 for a simplified graphical.

[14] Per The Potomac Edison Company - MD, FERC Form No. 1, Year/Period of Report, End of 2021/Q4, Account 364, Balance at End of Year, pg. 206.

FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES

This plant distribution account is predominately made up of the various overhead distribution line conductors, operating at either primary or secondary voltage. This study considered primary conductors only, the Company's GIS data is not sufficient to perform a similar analysis on the costs of secondary and/or service conductors.

Assumptions and Method

The primary conductors are allocated to both primary and secondary rates. To simplify the summations the conductors were divided into two sizes: large and small. The unique conductor paths, avoiding the duplicate counting of conductors, were calculated for all the primary customers back to the breaker on each circuit. The primary conductors were separated into small and large size conductors.

Conductor size and length assumptions are the same as the minimum grid portion of the study. Conductor lengths were summed by primary rate customer or non-primary rate customer (i.e., Secondary).

A weighting is then used to account for the differences in cost to install a mile of large vs. small conductor. The weighted conductor length for primary conductors feeding primary rate customers is then compared to the weighted total conductor length of all conductors to obtain the percentage of primary conductor used by the primary rate customers. Sections of Primary conductor were only counted once and assigned to the primary rate customer portion of this account.

FERC Account 365 OVERHEAD CONDUCTORS AND DEVICES SPLIT OF PLANT					
Company	Total Plant Value	Primary Customers		Secondary Customers	
		Percent	Value	Percent	Value
Potomac Edison Maryland	$226,243,593[15]	5.3%	$12,061,858	94.7%	$214,181,735

When a device or structure serves multiple primary customers, it is only counted one time in the results. See Figure 1 for a simplified graphical.

[15] Per The Potomac Edison Company - MD, FERC Form No. 1, Year/Period of Report, End of 2021/Q4, Account 365, Balance at End of Year, pg. 206.

FERC Account 366 – UNDERGROUND CONDUIT

Conduit systems are used to supply both the primary rate and secondary rate customers. Most of the conduit system is used to protect primary cable (which can be used to serve both primary customers, and secondary customers via transformation), and of that majority, the bulk of the primary conduit system is installed to protect large primary cables. Said another way, where majority of the large-sized primary cables are installed in conduit, and the majority of the small-sized primary cables are direct buried. Most secondary cables are direct buried.

Assumptions and Method

The circuit length of unique large sized, underground primary conductor feet is obtained by obtaining the span length of each primary line segment and summing to obtain the total primary circuit feet used to serve primary customers. The same process is used for determining the total circuit feet for all large primary conductors in the system.

- Conductors with a blank or unknown conductor type/size were omitted
- Conductor segments greater than 2,500' were considered data errors and omitted

The circuit length for large primary conductors, serving primary rate customers, is then compared to the total large primary circuit length to obtain the percentage of conduit systems used by the primary rate customers.

FERC Account 366 UNDERGROUND CONDUIT SPLIT OF PLANT					
Company	Total Plant Value	Primary Customers		Secondary Customers	
		Percent	Value	Percent	Value
Potomac Edison Maryland	$65,979,243[16]	5.1%	$3,344,869	94.9%	$62,634,374

When a device or structure serves multiple primary customers, it is only counted one time in the results. See Figure 1 for a simplified graphical.

[16] Per The Potomac Edison Company - MD, FERC Form No. 1, Year/Period of Report, End of 2021/Q4, Account 366, Balance at End of Year, pg. 206.

FERC Account 367 – UNDERGROUND CONDUCTORS & DEVICES

This plant distribution account is predominately made up of the various underground distribution line conductors, operating at either primary or secondary voltage. This study considered primary conductors only, the Company's GIS data is not sufficient to perform a similar analysis on the costs of secondary and/or service conductors.

Assumptions and Method

The primary conductors are allocated to both primary and secondary rates. To simplify the summations the conductors were divided into two sizes: large and small. The unique conductor paths, avoiding the duplicate counting of conductors, were calculated for all the primary customers back to the breaker on each circuit. The primary conductors were separated into small and large size conductors.

- Conductors with a blank or unknown conductor type/size were omitted
- Conductor segments greater than 2,500' were considered data errors and omitted

The conductor length of unique primary conductor feet is obtained by obtaining the span length of each primary line segment and then, by segment, accounting for the number of conductors (1-phase vs 3-phase) and summing to obtain the total primary conductor mileage used to serve primary customers. The same process is used for determining the total conductor mileage for all primary conductors in the system.

A weighting is then used to account for the differences in cost to install a mile of large vs. small conductor. The weighted conductor length for primary conductors feeding primary rate customers is then compared to the weighted total conductor length of all conductors to obtain the percentage of primary conductor used by the primary rate customers.

FERC Account 367 UNDERGROUND CONDUCTORS AND DEVICES SPLIT OF PLANT					
Company	Total Plant Value	Primary Customers		Secondary Customers	
		Percent	Value	Percent	Value
Potomac Edison Maryland	$295,149,931[17]	2.2%	$6,437,659	97.8%	$288,712,272

When a device or structure serves multiple primary customers, it is only counted one time in the results. See Figure 1 for a simplified graphical.

[17] Per The Potomac Edison Company - MD, FERC Form No. 1, Year/Period of Report, End of 2021/Q4, Account 367, Balance at End of Year, pg. 206.

Streetlight Component of

FERC Account 364 – POLES, TOWERS, AND FIXTURES

FERC Account 364 – POLES, TOWERS, AND FIXTURES

This plant distribution account is predominately made up of the various wood distribution poles used to support primary and secondary distribution conductors.

Assumptions and Method

- The Company's GIS was used to determine the number of streetlights on distribution poles, by size and install year of the pole.
  - The count of poles does not identify if the pole is used for anything other than streetlights. (i.e. distribution primary or secondary conductors)
  - Streetlights attached to joint use poles were not included.
  - Poles taller than 55 feet were excluded from this study.
- The current installed cost for each size pole was obtained from CREWS and trended by size to build a list of costs by pole length for each size wood pole.
- The install years were used to age the current costs for the actual size poles using Handy-Whitman indices and extended by the number of poles in service for each year, then summed to develop the streetlight component for this plant account.

FERC Account 364 POLES, TOWERS, AND FIXTURES SPLIT OF PLANT			
Company	Total Plant Value	Streetlight Costs	
		Percent	Value
Potomac Edison Maryland	$128,631,437[18]	2.5%	$3,245,022

[18] Per The Potomac Edison Company - MD, FERC Form No. 1, Year/Period of Report, End of 2021/Q4, Account 364, Balance at End of Year, pg. 206.

Overhead & Underground Component of

FERC Account 368 – LINE TRANSFORMERS

FERC Account 369 – SERVICES

FERC Account 368 - LINE TRANSFORMERS

This plant distribution account is predominately made up of the various distribution transformers used to step the distribution voltage down to the service-voltage level delivered to the customer. This account includes both overhead and pad-mounted transformers.

Assumptions and Method

- The Company's GIS system was used to determine the number of overhead and pad-mounted distribution transformers, by size and install year, to be replaced by the minimum size (25 KVA Single Phase) overhead line transformer that is in common use within the study territory.
- The current installed cost for each size line transformer was obtained from CREWS and trended by size to build a list of costs by size for each size overhead and pad-mounted distribution transformer.
- The install years were used to age the current costs for the actual size and minimum size transformers using Handy-Whitman indices and extended by the number of transformers in service for each year, then summed to develop the customer component for this plant account.
- Transformers missing install year, construction type, or kVA were omitted.
- The percentage of minimum size cost, of the calculated current cost was calculated as the portion represented by the cost of the minimum sized units.
- Utilizing the minimum grid valuation, the population was further subdivided into Overhead (OH) and Underground (UG) where overhead line transformers were assigned into the OH category and Padmount (single and 3 phase) were assigned into the UG category.

FERC Account 368 LINE TRANSFOMERS SPLIT OF PLANT					
Company	Total Plant Value	Overhead		Underground	
		Percent	Value	Percent	Value
Potomac Edison Maryland	$201,703,535[19]	41.4%	$83,428,827	58.6%	$118,274,708

[19] Per The Potomac Edison Company - MD, FERC Form No. 1, Year/Period of Report, End of 2021/Q4, Account 368, Balance at End of Year, pg. 206.

FERC Account 369 - SERVICES

This plant distribution account is predominately made up of the secondary conductors and hardware used to connect from the last transformation (FERC Account 368) to the customer meter. This plant distribution account is a combination of Overhead (OH) and Underground (UG).

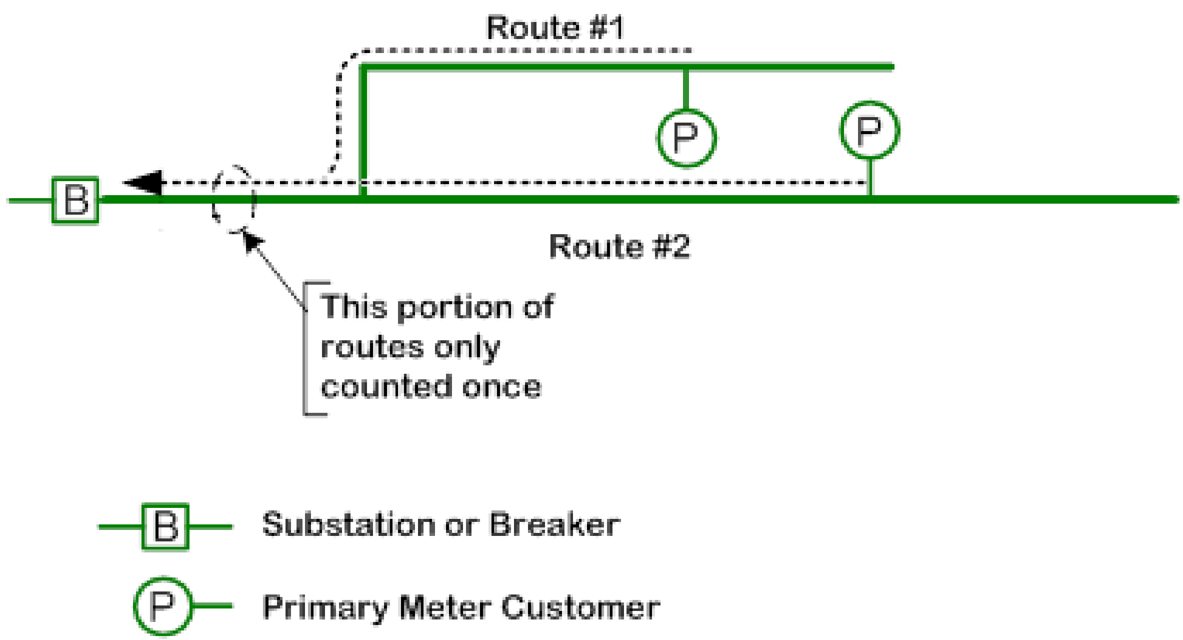
Assumptions and Method

- The Company's GIS system was used to determine the combined length of the secondary (service) conductor.
- Conductor lengths between 1 and 750 feet were included. Conductor lengths lacking detail or longer than 750 feet per segment were excluded.
- Due to incomplete data associated with installation, a Handy Whitman style value adjustment was not performed, the ratios below are based only on length.
- Inconsistencies with conductor quantities also resulted in the omission of this parameter as part of the analysis (i.e., conductor count was not used as a factor to scale 3 phase vs single phase).
- Establishing the Overhead vs Underground ratios for this plant account was done based on available data within the company's GIS system. The data available for this commodity type is less complete than the other plant accounts presented within this report and is therefore an extrapolation of the service territory based on available data.

FERC Account 369 SERVICES SPLIT OF PLANT					
Company	Total Plant Value	Overhead		Underground	
		Percent	Value	Percent	Value
Potomac Edison Maryland	$71,194,334[20]	70.9%	$50,483,190	29.1%	$20,711,144

[20] Per The Potomac Edison Company - MD, FERC Form No. 1, Year/Period of Report, End of 2021/Q4, Account 368, Balance at End of Year, pg. 206.

Figure 1 – Primary Customer Connection & Routing



BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

JILL A. SOLTIS

Concerning: Revenue Requirements; Ratemaking Adjustments

March 22, 2023

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jill A. Soltis, and my business address is 800 Cabin Hill Drive, Greensburg, Pennsylvania 15601.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by FirstEnergy Service Company and my title is Analyst V, Rates and Regulatory Affairs. My duties include developing and providing detailed and qualitative analysis on behalf of The Potomac Edison Company ("PE" or "Company") and Monongahela Power Company ("Mon Power"), including quarterly reporting of Federal Energy Regulatory Commission ("FERC") jurisdictional financial data, participating in regulatory proceedings, and developing revenue requirements.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I am a graduate of Seton Hill University where I earned a Bachelor of Science degree in Business Administration with an Information Management minor. I have over 32 years of experience with FirstEnergy Service Company or its predecessor companies and have held positions of Customer Service Representative; Customer Service Compliance Specialist; Technician, Load Data Services; Power Scheduler; Analyst IV, Retail Tariff Analysis and Forecasting; Senior Analyst, Human Services; Analyst IV, Rates and Regulatory Affairs, and my current position of Analyst V, Rates and Regulatory Affairs.

Q. HAVE YOU TESTIFIED IN RATE PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes, I have testified on behalf of PE and its affiliate Mon Power before the Public Service Commission of West Virginia in their 2021 Vegetation Management Surcharge filing in Case No. 21-0659-E-P and the 2020 Expanded Net Energy Cost filing in Case No. 20-0665-E-ENEC.

II. PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony is to explain and support the Company's:

1) Distribution-related revenue requirement;
2) Going-level adjustments; and
3) Pro forma adjustments.

All the going-level and pro forma adjustments to the test year data are summarized on the exhibits and supporting data I am sponsoring. The following tables list all the adjustments including number, sponsoring witness, and description.

Going-Level Adjustment	Sponsoring Witness	Description
1	Colflesh	Salaries and Wages – Test Year
2	Colflesh	Salaries and Wages – 2023
3	Colflesh	Employee Savings Plan – Test Year
4	Colflesh	Employee Savings Plan – 2023
5	Ward	Storm Damage Expenses
6	Ward	Advertising Expenses

Going-Level Adjustment	Sponsoring Witness	Description
7	Ward	Postage Expense
8	Ward	Commission Assessment Expense
9	Colflesh	Medical Insurance Expense
10	Colflesh	Group Life Insurance Expense
11	Ashton	Pension/OPEB Mark-to-Market
12	Ashton	Pension/OPEB Non-Mark-to-Market
13	Ward	Rate Case Expense
14	Colflesh	COVID-19 Expense
15	Colflesh	Service Company Carrying Charges
16	Ward	New Depreciation Rates
17	Soltis	Depreciation Expense on Reliability Projects – Test Year
18	Soltis	Depreciation Expense on Reliability Projects – Post Test Year
19	Ward	Rate Case Amortization Expense
20	Colflesh	Service Company Allocation of Depreciation Expense
21	Colflesh	Conservation Voltage Reduction
22	Colflesh	COVID-19 Deferrals
23	Colflesh	COVID-19 Regulatory Debit
24	Ward	Electric Vehicle Portfolio Program Regulatory Asset Amortization
25	Ward	Electric Vehicle Portfolio Program deferral
26	Colflesh	Payroll Taxes Salaries and Wages – Test Year
27	Colflesh	Payroll Taxes Salaries and Wages – 2023

Going-Level Adjustment	Sponsoring Witness	Description
28	Soltis	Interest Synchronization
29	Soltis	State Income Taxes
30	Soltis	Federal Income Taxes
31	Soltis	Reliability Projects – Test Year
32 A	Soltis	Reliability Projects – Post Test Year
32 B	Soltis	Reliability Projects – Construction Work in Progress -- Test Year
33	Soltis	Accumulated Depreciation Reliability Projects – Test Year
34	Soltis	Accumulated Depreciation Reliability Projects – Post Test Year
35	Soltis	Allocation of Service Company Materials and Supplies
36	Soltis	Cash Working Capital
37	Soltis	Accumulated Deferred Income Taxes ("ADIT") Reliability Projects – Test Year
38	Soltis	ADIT Reliability Projects – Post Test Year
39 A	Colflesh	Allocation of Service Company Plant-in-Service
39 B	Colflesh	Allocation of Service Company Depreciation Reserve
39 C	Colflesh	Allocation of Service Company ADIT
40	Colflesh	Rate Base Increase for COVID-19 Regulatory Asset
41	Ward	Rate Base Increase for Electric Vehicle Portfolio Program Regulatory Asset
42	Ashton	Rate Base decrease for non-eligible amounts
43	Ashton	Out of period adjustments

Pro Forma Adjustment	Sponsoring Witness	Description
44	Soltis	Pro Forma Revenue Requirement
45	Soltis	Pro Forma Uncollectible Expense
46	Soltis	Pro Forma Maryland Regulatory Assessment
47	Soltis	Pro Forma Maryland Gross Receipt Tax
48	Soltis	Pro Forma State Income Tax
49	Soltis	Pro Forma Federal Income Tax

The going-level adjustments that I am sponsoring are as follows:

(a) Terminal Treatment of Test Year Reliability Plant

- Adjustment No. 3-17 Depreciation Expense on Terminal Treatment Reliability Projects
- Adjustment No. 3-31 Terminal Treatment of Reliability Projects
- Adjustment No. 3-33 Accumulated Depreciation on Terminal Treatment of Reliability Projects
- Adjustment No. 3-37 Accumulated Deferred Income Taxes on Terminal Treatment of Reliability Project

(b) Terminal Treatment of Post-Test Year Reliability Plant

- Adjustment No. 3-18 Depreciation Expense on Terminal Treatment of Reliability Projects - Post Test Year, 6-Months Ended June 2023
- Adjustment No. 3-32a Terminal Treatment of Reliability Projects – Post Test Year, 6-Months Ended June 2023

- Adjustment No. 3-32b Terminal treatment of Construction Work in Progress of Test Year Reliability projects.
- Adjustment No. 3-34 Accumulated Depreciation on Terminal Treatment of Reliability Projects - Post Test Year, 6-Months Ended June 2023
- Adjustment No. 3-38 Accumulated Deferred Income Taxes on Terminal Treatment of Reliability Projects – Post Year, 6-Months Ended June 2023

(c) Adjustment No. 3-28 Interest Synchronization
(d) Adjustment No. 3-29 State Income Taxes on Going-Level Adjustments
(e) Adjustment No. 3-30 Federal Income Tax on Going-Level Adjustments
(f) Adjustment No. 3-35 Materials and Supplies Recorded on Service Company Books
(g) Adjustment No. 3-36 Cash Working Capital on Going-Level Adjustments

The pro forma adjustments that I am sponsoring are as follows:

(a) Adjustment No. 3-44 Pro Forma Revenue Requirement
(b) Adjustment No. 3-45 Pro Forma Uncollectible Expense
(c) Adjustment No. 3-46 Pro Forma Regulatory Assessment
(d) Adjustment No. 3-47 Pro Forma Maryland Gross Receipts Tax
(e) Adjustment No. 3-48 Pro Forma State Income Tax
(f) Adjustment No. 3-49 Pro Forma Federal Income Tax

Q. WHAT IS THE DIFFERENCE BETWEEN GOING-LEVEL AND PRO FORMA ADJUSTMENTS?

A. Going-level adjustments are adjustments made to the test year to reflect revenues, expenses, and rate base on a going-level basis. Such adjustments enable the Company to capture the effects of relevant changes which occurred during or after the test year. As such, the inclusion of going-level adjustments into a test year reflects a fully adjusted test year *prior* to the Company's proposed revenue change or change in expenses related to the proposed revenue change. Pro forma adjustments are adjustments to revenues (and changes in expenses related to the revenue change) necessary to provide the Company an opportunity to earn its requested rate of return.

Q. WHAT IS THE TEST YEAR USED IN THIS FILING?

A. The test year is the 12-month period from January 1, 2022, through December 31, 2022. The test year includes twelve months of actual data.

Q. HAVE YOU PREPARED OR HAD PREPARED UNDER YOUR SUPERVISION EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A. Yes, I have. Exhibits JAS-1 through JAS-5 were prepared by me or under my supervision and are described in detail in my testimony.

III. RATE INCREASE REQUEST

Q. PLEASE DESCRIBE THE INFORMATION YOU WILL BE PROVIDING RELATED TO THE COMPANY'S DISTRIBUTION-RELATED REVENUE REQUIREMENT.

A. Exhibit JAS-1 provides a summary of PE Total Company and Maryland Electric Distribution financial results for the test year. Exhibit JAS-1 shows a per-book rate of return ("ROR") of 4.06% and a return on equity ("ROE") of 4.10% with a fully adjusted going-level ROR of 2.90% and a fully adjusted ROE of 1.93%. This contrasts with the Company's current authorized ROR of 7.15% and current authorized ROE of 9.65% from Order No. 89072 issued March 22, 2019, in Case No. 9490. Exhibit JAS-4 also shows the calculation of the increase in revenues needed to earn the 7.54% ROR described in the direct testimony of Company witness Wang. Based on the data provided in the exhibits, the Company is requesting a distribution base revenue increase of $47,492,648. The request of $47.5 million was determined using the Company's Maryland jurisdictional distribution-allocated financial results adjusted with known and measurable adjustments to the test year ending December 31, 2022. The method for determining a Maryland jurisdictional distribution basis is discussed in the direct testimony of Company witness Colflesh.

IV. RATEMAKING ADJUSTMENTS

A. Going-Level Adjustments

Q. WILL YOU BRIEFLY DESCRIBE EACH OF THE ADJUSTMENTS IN THIS CASE USING THE CATEGORIES AND NUMBERS SHOWN IN THE TABLE ABOVE AND IN EXHIBIT JAS-2?

A. Yes.

Q. PLEASE EXPLAIN ADJUSTMENTS NOS. 1 AND 2 (SALARIES AND WAGES).

A. Adjustment No. 1 is a going-level adjustment that annualizes salary and wage increases that occurred during the test year. Adjustment No. 2 is a going-level adjustment that annualizes salary and wage increases that occurred during 2023. Company witness Colflesh is sponsoring these adjustments and provides further detail in her testimony.

Q. PLEASE EXPLAIN ADJUSTMENT NOS. 3 AND 4 (EMPLOYEE SAVINGS PLAN).

A. Adjustment No. 3 is a going-level adjustment that annualizes employee savings plan expenses related to the increase in salaries and wages during the test year. Adjustment No. 4 is a going-level adjustment that annualizes employee savings plan expenses related to the increase in salaries and wages during 2023. Company witness Colflesh is sponsoring these adjustments and provides further detail in her testimony.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 5 (STORM DAMAGE EXPENSES).

A. Adjustment No. 5 is a going-level adjustment that modifies the test year operation and maintenance ("O&M") expense to a five-year average level of storm damage expense. Company witness Ward is sponsoring this adjustment and provides further detail in her testimony.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 6 (REMOVAL OF ADVERTISING EXPENSE).

A. Adjustment No. 6 is a going-level adjustment that removes non-eligible advertising expense from the test year. Company witness Ward is sponsoring this adjustment and provides further detail in her testimony.

Q. WHAT IS ADJUSTMENT NO. 7 (POSTAGE EXPENSE)?

A. Adjustment No. 7 is a going-level adjustment that increases the test year customer account postage costs. Company witness Ward is sponsoring this adjustment and provides further detail in her testimony.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 8 (COMMISSION ASSESSMENT EXPENSE).

A. Adjustment No. 8 is a going-level adjustment that increases the test year level of regulatory commission assessment expense. Company witness Ward is sponsoring this adjustment and provides further detail in her testimony.

Q. WHAT ARE ADJUSTMENT NOS. 9 AND 10 (MEDICAL INSURANCE AND GROUP LIFE INSURANCE EXPENSES)?

A. Adjustment No. 9 is a going-level adjustment that annualizes the increase in medical insurance expenses, and Adjustment No. 10 is a going-level adjustment that annualizes the group life insurance increase during the test year. Company witness Colflesh is sponsoring these adjustments and provides further detail in her testimony.

Q. WHAT IS ADJUSTMENT NO. 11 (PENSION/OPEB MARK-TO-MARKET)?

A. Adjustment No. 11 is a going-level adjustment that, for ratemaking purposes, smooths the effects of the mark-to-market adjustments to pension and other post-employment benefits ("OPEB") expenses. Company witness Ashton is sponsoring this adjustment and provides further detail in her testimony.

Q. PLEASE EXPLAIN THE PURPOSE OF ADJUSTMENT NO. 12 (PENSION/OPEB NON-MARK-TO-MARKET).

A. Adjustment No. 12 is a going-level adjustment that averages the non-mark-to-market pension OPEB expenses for the five years ending December 31, 2022. Company witness Ashton is sponsoring this adjustment and provides further detail in her testimony.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 13 (RATE CASE EXPENSE).

A. Adjustment No. 13 is a going-level adjustment that increases amortization expenses in the test year to recover rate case expenses over a three-year period. Company witness Ward is sponsoring this adjustment and provides further detail in her testimony.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 14 (REMOVAL OF COVID-19 EXPENSE).

A. Adjustment No. 14 is a going-level adjustment to O&M to remove expenses related to COVID-19. Company witness Colflesh is sponsoring this adjustment and provides further detail in her testimony.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 15 (REMOVAL OF FESC CARRYING CHARGES).

A. Adjustment No. 15 is an adjustment to O&M expense to remove FirstEnergy Service Company ("FESC") carrying charges. Company witness Colflesh is sponsoring this adjustment and provides further detail in her testimony.

Q. WHAT IS ADJUSTMENT NO. 16 (NEW DEPRECIATION RATES)?

A. Adjustment No. 16 is an adjustment to increase depreciation expense to reflect the new proposed depreciation rates. Company witness Ward is sponsoring this adjustment which is based upon Company witness Spanos' depreciation study and provides further detail in her testimony.

Q. PLEASE EXPLAIN ADJUSTMENT NOS. 17 AND 18 (DEPRECIATION EXPENSE).

A. Adjustment No. 17 is to reflect the going-level increase in depreciation expense associated with the terminal treatment of capital expenditures for reliability-related projects placed in service during the test year. Adjustment No. 18 is to reflect the going-level increase in depreciation expense associated with the terminal treatment of capital expenditures for reliability-related projects to be placed in service between the end of the test year (December 31, 2022) and June 30, 2023, prior to the anticipated start of hearings. Terminal treatment is the recognition of expenditures for capital projects as if the expenditures had been included in rate base in full during the entire test year instead of taking a monthly average in service value. The adjustments were made by comparing the terminal (i.e., end of period) value to the test year 13-month average of these non-revenue-producing facilities and then adjusting plant-in-service, accumulated depreciation, ADIT, and depreciation expense to reflect the differences. The Maryland Public Service Commission ("Commission") has previously permitted terminal treatment for the Company for non-revenue-producing capital expenditures. The rate base effect of capital expenditures for test year and post-test year reliability-related projects are discussed in connection with Adjustment Nos. 31 and 32.

Q. WHAT IS ADJUSTMENT NO. 19 (REMOVAL OF PRIOR RATE CASE EXPENSE AMORTIZATION)?

A. Adjustment No. 19 is to remove the prior rate case expense amortization. Company witness Ward is sponsoring this adjustment and provides further detail in her testimony.

Q. WHAT IS ADJUSTMENT NO. 20 (FESC ALLOCATION OF DEPRECIATION EXPENSE)?

A. Adjustment No. 20 is to adjust depreciation and amortization expense for FESC allocation of depreciation expense. Company witness Colflesh is sponsoring this adjustment and provides further detail in her testimony.

Q. WHAT IS ADJUSTMENT NO. 21 (CONSERVATION VOLTAGE REDUCTION)?

A. Adjustment No. 21 is a going-level adjustment to the test year regulatory credit to reflect removal of the Company's Conservation Voltage Reduction Program recovery. Company witness Colflesh is sponsoring this adjustment and provides further detail in her testimony.

Q. **PLEASE EXPLAIN ADJUSTMENT NOS. 22 AND 23 (COVID-19 DEFERRALS AND REGULATORY DEBIT).**

A. Adjustment No. 22 is to remove COVID-19 deferrals in the test year. Adjustment No. 23 is to adjust regulatory debits to add recovery of COVID-19 regulatory asset amortization. Company witness Colflesh is sponsoring these adjustments and provides further detail in her testimony.

Q. WHAT ARE ADJUSTMENT NOS. 24 AND 25 (EV PORTFOLIO PROGRAM REGULATORY ASSET AMORTIZATION AND DEFERRAL)?

A. Adjustment No. 24 is to adjust regulatory debits to add recovery of Electric Vehicle Portfolio Program regulatory asset amortization. Adjustment No. 25 is to adjust regulatory credits to remove the Electric Vehicle Portfolio Program deferrals in the test year. Company witness Ward is sponsoring these adjustments and provides further detail in her testimony.

Q. WHAT ARE ADJUSTMENT NOS. 26 AND 27 (PAYROLL TAXES SALARIES AND WAGES EXPENSE)?

A. Adjustment No. 26 is a going-level adjustment that annualizes the payroll tax expenses associated with the increase in salaries and wages in the test year. Adjustment No. 27 is a going-level adjustment that annualizes the payroll tax expense associated with the 2023 increase in salaries and wages. Company witness Colflesh is sponsoring this adjustment and provides further detail in her testimony.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 28 (INTEREST SYNCHRONIZATION).

A. Adjustment No. 28 is a going-level adjustment to synchronize the income tax interest expense deduction with interest expense calculated on the debt terms (amount and interest rate) used for the calculation of the overall ROR. This produces a different level of interest expense than the amount that was incurred by the Company during the test year. Since interest expense is a tax deduction, the income tax expense needs to be adjusted to reflect either the greater or lesser amount of income taxes that would be due based upon the use of the ratemaking debt assumptions. This amount was calculated by first multiplying the going-level rate base by the weighted average cost of debt to yield the going-level interest expense used for the ROR calculation. From this amount, the actual interest expense deducted for income tax purposes is subtracted to achieve the required change to interest expense. This amount was then applied to the respective state and federal income tax rate calculations to determine the interest synchronization adjustment.

Q. PLEASE EXPLAIN ADJUSTMENT NOS. 29 AND 30 (STATE AND FEDERAL INCOME TAXES).

A. These adjustments are tax related. Adjustment No. 29 is to reflect a decrease in state income tax expense related to the going-level adjustments that are subject to state income tax, whereas Adjustment No. 30 is to reflect a decrease in federal income tax expense related to the going-level adjustments that are subject to federal income tax.

Q. PLEASE EXPLAIN ADJUSTMENT NOS. 31 AND 32 (RELIABILITY PROJECTS).

A. Adjustment No. 31 is a rate base adjustment to increase plant-in-service to reflect terminal treatment of capital expenditures for reliability-related projects placed in service during the test year. Adjustment No. 32 is also a rate base adjustment and increases plant-in-service to reflect terminal treatment of capital expenditures for reliability-related projects to be placed in service between the end of the test year (December 31, 2022) and the end of June 2023, prior to the anticipated hearing in this case. The reliability-related expenditures reflected in Adjustment No. 31 were not placed in service at the beginning of the test year and were adjusted to reflect a full 13-month inclusion in average rate base in the test year. The reliability-related expenditures reflected in Adjustment No. 32a will occur post-test year, and they do not have to be adjusted in order to receive terminal treatment. The reliability-related expenditures reflected in Adjustment No. 32b include the terminal treatment of CWIP for two large projects (West Jefferson Substation and Myersville Energy Storage) to reflect a full 13-month inclusion in average rate base in the test year.

These construction projects are needed to improve reliability by upgrading and modernizing the distribution system. These investments in plant, property, and equipment are non-revenue-producing and instead support the provision of reliable and safe electric service to customers. Reliability-related projects benefit existing customers, and customers realize these benefits as soon as the facilities are in service, which can be before the facilities are moved to plant-in-service from an accounting standpoint. In these situations, customers see improved system performance during all weather conditions, including storms, and fewer outages overall.

Q. PLEASE EXPLAIN ADJUSTMENT NOS. 33 AND 34 (ACCUMULATED DEPRECIATION RELIABILITY PROJECTS).

A. These adjustments are related to Adjustment Nos. 31 and 32 for the terminal treatment of reliability-related capital projects. Adjustment No. 33 is a rate base adjustment to reflect the increase in accumulated depreciation associated with the terminal treatment of capital expenditures for reliability-related projects during the test year, whereas Adjustment No. 34 is a rate base adjustment to reflect the increase in accumulated depreciation associated with the terminal treatment of capital expenditures for reliability-related projects placed in service between the end of the test year, December 31, 2022, and June 30, 2023.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT NO. 35 (ALLOCATION OF FESC MATERIALS AND SUPPLIES)?

A. The purpose of Adjustment No. 35 is to increase materials and supplies inventory in rate base to reflect distribution inventory allocated to PE Maryland held by FESC and recorded on FESC's books rather than PE's books. Per Commission Order issued January 17, 2012, in Case No. 9233, the Commission granted PE approval (subject to certain conditions which have been met) to participate in the Utility Inventory Management System operated by FESC.

The calculation of the inventory included in this adjustment was first to arrive at the Maryland distribution inventory (excluding centralized meters). This was done by including the FESC distribution inventory located in Maryland, which is for use in PE Maryland. In addition, a portion of the distribution shared inventory not located in Maryland (excluding centralized meters) was included and allocated first to PE based on FirstEnergy's Cost Allocation Manual ("CAM") multifactor allocation. From this PE-allocated portion, an additional step was necessary to allocate to Maryland distribution. This allocation was based on the average number of customers served by PE in Maryland and material specific to distribution.

The second inventory calculation step included an allocation of centralized meters at three locations (i.e., Bethel, North Street and Connellsville). To allocate the centralized meter inventory costs to Maryland distribution, an allocation based on both the meters served by meter inventory operating company location and then the number of customers served in Maryland, was performed.

Q. WHAT IS ADJUSTMENT NO. 36 (CASH WORKING CAPITAL)?

A. Adjustment No. 36 is a rate base adjustment to reflect the going-level amount of cash working capital ("CWC") associated with the adjustments in this case. For ratemaking purposes, CWC is generally defined as the average amount of capital provided by investors, over and above the investment in plant and other specifically identified rate base items, to bridge the gap between the time expenditures are required to be made by the Company to provide service and the time collections are received for that service. CWC is determined for rate making purposes by a lead/lag study which is described in the testimony of Company witness Lyons.

Q. PLEASE EXPLAIN ADJUSTMENT NOS. 37 AND 38 (ADIT RELIABILITY PROJECTS).

A. Adjustment No. 37 is a rate base adjustment for ADIT related to the test year terminal treatment of reliability-related plant whereas adjustment No. 38 is an adjustment for ADIT related to reliability-related projects placed in service between the end of the test year, December 31, 2022, and June 30, 2023. These adjustments are related to Adjustment Nos. 31 and 32.

Q. WAS THE EFFECT OF CAPITAL REPAIRS TAKEN INTO ACCOUNT WHEN ADIT WAS CALCULATED IN ADJUSTMENT NOS. 37 AND 38?

A. Yes, Adjustment Nos. 37 and 38 included an adjustment for capital repairs in the calculation of the ADIT. Consistent with the Commission's March 22, 2019 Order in the Company's 2018 base distribution rate case, Case No. 9490, the capital repairs were estimated based on a 3-year average of capital repairs as a percentage of distribution plant additions.[1]

Q. WHAT ARE ADJUSTMENT NOS. 39a, 39b, AND 39c (FESC ALLOCATIONS)?

A. Adjustment No. 39a is a rate base adjustment for the FESC allocation of plant-in-service, Adjustment No. 39b is a rate base adjustment for the FESC allocation of depreciation reserve, and Adjustment No. 39c is a rate base adjustment for the FESC allocation of ADIT.

[1] Order at 29-30.

Company witness Colflesh is sponsoring these adjustments and provides further detail in her testimony.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 40 (COVID-19 REGULATORY ASSET).

A. Adjustment No. 40 is an adjustment to increase rate base for the COVID-19 regulatory asset. Company witness Colflesh is sponsoring this adjustment and provides further detail in her testimony.

Q. PLEASE EXPLAIN ADJUSTMENT NO 41 (EV PORTFOLIO PROGRAM REGULATORY ASSET).

A. Adjustment No. 41 is an adjustment to increase rate base for the Electric Vehicle ("EV") Portfolio Program regulatory asset. Company witness Ward is sponsoring this adjustment which is supported by Company witness Warner's EV study and provides further detail in her testimony.

Q. WHAT IS ADJUSTMENT NO. 42 (NON-ELIGIBLE AMOUNTS)?

A. Adjustment No. 42 is an adjustment to rate base to remove non-eligible amounts. Company witness Ashton is sponsoring this adjustment and provides further detail in her testimony.

Q. WHAT IS ADJUSTMENT NO. 43 (OUT-OF-PERIOD ADJUSTMENTS)?

A. Adjustment No. 43 is an adjustment to the test year to remove any out-of-period accounting items. Company witness Ashton is sponsoring this adjustment and provides further detail in her testimony.

B. Pro Forma Adjustments

Q. PLEASE EXPLAIN ADJUSTMENT NO. 44 (PRO FORMA REVENUE REQUIREMENT).

A. Adjustment No. 44 is a pro forma adjustment to reflect the revenue the Company needs to achieve to earn a requested ROR of 7.54%.

Q. PLEASE EXPLAIN ADJUSTMENT NOS. 45 AND 46 (PRO FORMA UNCOLLECTIBLE EXPENSE AND MARYLAND REGULATORY ASSESSMENT).

A. Adjustment No. 45 is a pro forma adjustment of uncollectible debt expense associated with pro forma revenues provided in Adjustment No. 44. The appropriate level of uncollectible expense was determined using the actual net uncollectibles as compared to revenues for the test year and applying this percentage to adjusted revenues. This is the same method accepted by the Commission in the Company's 2018 base distribution rate case where the revenue conversion factor included the uncollectible rate. Adjustment No. 46 is a pro forma adjustment of the Commission regulatory assessment fee associated with pro forma revenues provided in Adjustment No. 44. The appropriate level of regulatory assessment was determined by applying the current Commission assessment rate to the pro forma revenues. As with Adjustment No. 45, this adjustment is the same method accepted by the Commission in the Company's 2018 base distribution rate case.

Q. PLEASE EXPLAIN ADJUSTMENT NOS. 47, 48 AND 49 (PRO FORMA MARYLAND GROSS RECEIPT TAX AND PRO FORMA STATE AND FEDERAL INCOME TAXES).

A. These pro forma adjustments are all tax items related to the revenue the Company needs to achieve to earn a requested ROR of 7.54%. Adjustment No. 47 is a pro forma adjustment to reflect Maryland gross receipts tax on the pro forma revenues provided in Adjustment No. 44; Adjustment No. 48 is a pro forma adjustment to reflect the increase in Maryland state income tax on the pro forma revenues provided in Adjustment No. 44; and Adjustment No. 49 is a pro forma adjustment to reflect the increase in federal income tax on the pro forma revenues provided in Adjustment No. 44.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

The Potomac Edison Company
Maryland Distribution Rate of Return
12 Months Ending December 31, 2022

			Maryland					
Line No.	Item Column (1)	Total Company (2)	Electric Distr bution (3)	Adjustments (4)	Going Level (5)	Pro Forma Adjustments (6)	Pro Forma (7)
1	Operating Revenues	$ 948,557,379	$ 138,842,885		$ 138,842,885	$ 47,492,648	$ 186,335,533
2							
3	O & M Expense	$ 717,381,346	$ 59,657,983	$ (3,002,598)	$ 56,655,385	532,379	$ 57,187,765
4	Depreciation and Amortization Expense	59,010,352	27,614,934	6,207,090	33,822,024		33,822,024
5	Regulatory Debits	10,047,784	938,317	(938,317)	-		-
6	Regulatory Credits	14,926,305	(3,215,103)	4,503,455	1,288,352		1,288,352
7	Accretion Expense	22,788					-
8	Taxes Other than Income Taxes	47,813,320	30,563,131	44,187	30,607,318	949,853	31,557,171
9	State Income Tax	(235,117)	(2,621,445)	(399,207)	(3,020,652)	3,795,859	775,207
10	Federal Income Tax	1,065,836	(6,122,265)	(932,331)	(7,054,596)	8,865,057	1,810,461
11	Deferred Income Taxes	19,067,939	8,298,486		8,298,486		8,298,486
12	Total Operating Expenses	$ 869,100,552	$ 115,114,038	$ 5,482,279	$ 120,596,317	$ 14,143,148	$ 134,739,466
13							
14	Operating Income	$ 79,456,827	$ 23,728,847	$ (5,482,279)	$ 18,246,568	$ 33,349,500	$ 51,596,067
15							
16	AFUDC	5,790,352	2,609,343		2,609,343		2,609,343
17	Interest on Customer Deposits	(22,016)	(17,180)		(17,180)		(17,180)
18	Earnings	$ 85,225,162	$ 26,321,010	$ (5,482,279)	$ 20,838,731	$ 33,349,500	$ 54,188,230
19							
20	Rate Base 13-Month Average						
21	Electric Plant in Service	$ 2,710,742,554	$ 1,400,595,796	$ 64,622,415	$ 1,465,218,211		$ 1,465,218,211
22	Less: Depreciation Reserve	1,146,938,030	560,424,574	16,625,062	577,049,637		577,049,637
23	Net Plant in Service	$ 1,563,804,524	$ 840,171,222	$ 47,997,353	$ 888,168,574	$ -	$ 888,168,574
24							
25	CWIP	$ 94,967,228	$ 42,795,678	$ 7,779,093	$ 50,574,771		$ 50,574,771
26	Working Capital	25,579,607	3,403,111	(158,960)	3,244,151		3,244,151
27	Plant Materials & Supplies			13,191,398	13,191,398		13,191,398
28	Plant Held For Future Use	-	-				
29	Prepaid Balances	17,924,746	-		-		-
30	Deferred Federal and State Tax Balance	293,096,867	219,665,469	5,809,772	225,475,241		225,475,241
31	Customer Deposits	19,589,516	14,024,604		14,024,604		14,024,604
32	Customer Advances	5,621,654	5,061,698		5,061,698		5,061,698
33	Regulatory Asset	-	-	7,907,867	7,907,867		7,907,867
34	Total Rate Base	$ 1,383,968,068	$ 647,618,240	$ 70,906,978	$ 718,525,219	$ -	$ 718,525,219
35							
36	Rate of Return	6.158%	4.064%		2.900%		7.54%
37							
38	Earnings		$ 26,321,010		$ 20,838,731		$ 54,188,230
39	Interest Expense		12,093,108		13,417,169		13,417,169
40	Available for Common		$ 14,227,902		$ 7,421,562		$ 40,771,061
41	Common Equity		$ 346,675,546		$ 384,632,654		$ 384,632,654
42							
43	Return on Equity		4.10%		1.93%		10.60%
44							
45	Capital Structure						
46	Total Long-term Debt	$ 671,287,336	46.47%	4.018%	1.87%		
47	Common Equity	$ 773,299,730	53.53%	10.600%	5.67%		

48	Total	$ 1,444,587,066	100.00%	7.542%

The Potomac Edison Company
Maryland Distribution Adjustment Summary
12 Months Ending December 31, 2022

Adjustment Number	(Witness)	Description		Maryland Distribution
		Going Level		
1	Colflesh	To annualize salaries and wages increases that occurred during the test year.	$	255,885
2	Colflesh	To annualize salaries and wages increases in 2023.	$	321,723
3	Colflesh	To annualize employee savings plan increases associated with increases in salaries and wages that occurred during the test year.	$	7,677
4	Colflesh	To annualize employee savings plan increases associated with increases in salaries and wages in 2023.	$	9,415
5	Ward	To adjust test year expenses for storm damages to a five year average going level.	$	(55,154)
6	Ward	To remove non-eligible related advertising expenses from the test year.	$	(66,751)
7	Ward	To increase postage expense related to changes in USPS postage rate.	$	46,132
8	Ward	To increase PSC assessment expense for change in assessment factor during the test year.	$	41,952
9	Colflesh	To annualize medical insurance expenses increases associated with increases in salaries and wages that occurred during the test year.	$	58,034
10	Colflesh	To annualize group life insurance expenses increases associated with increases in salaries and wages that occurred during the test year.	$	(543)
11	Ashton	To smooth the mark to market adjustments associated with changes in pensions and OPEBs.	$	(210,314)

The Potomac Edison Company
Maryland Distribution Adjustment Summary
12 Months Ending December 31, 2022

Adjustment Number	(Witness)	Description		Maryland Distribution
		Going Level		
12	Ashton	To adjust non-mark to market pension and OPEB expense to 5 year average.	$	1,172,567
13	Ward	To increase rate case expenses in the test year to recover rate case related charges over a three year time period.	$	423,557
14	Colflesh	To adjust test year O&M expense to remove items related to Covid-19.	$	(2,263,319)
15	Colflesh	To adjust O&M expense to remove service company charges.	$	(2,743,458)
16	Ward	To adjust depreciation expense for new depreciation rates.	$	3,000,258
17	Soltis	To increase depreciation expense for test year reliability projects.	$	596,217
18	Soltis	To increase depreciation expense for post test year reliability projects.	$	594,527
19	Ward	To adjust test year to remove rate case expense amortization.	$	(11,152)
20	Colflesh	To adjust depreciation and amortization expense for service company allocation of rate base.	$	2,016,088
21	Colflesh	To adjust the test year regulatory credit for removal of Conservation Voltage Reduction program.	$	(33,050)
22	Colflesh	To adjust regulatory credit to remove Covid-19 deferrals in test year.	$	2,263,319

The Potomac Edison Company
Maryland Distribution Adjustment Summary
12 Months Ending December 31, 2022

Adjustment Number	(Witness)	Description		Maryland Distribution
		Going Level		
23	Colflesh	To adjust regulatory debits to add Covid-19 regulatory asset amortization.	$	1,452,046
24	Ward	To adjust regulatory debits to add Electric Vehicle Portfolio Program regulatory asset amortization.	$	305,258
25	Ward	To adjust regulatory credit to remove Electric Vehicle Portfolio Program deferrals in test year.	$	527,034
26	Colflesh	To annualize payroll tax expenses associated with 2022 increases in salaries and wages.	$	19,575
27	Colflesh	To annualize payroll tax expenses associated with 2023 increases in salaries and wages.	$	24,612
28	Soltis	To reflect the State and Federal income tax effects of interest synchronization	$	543,454
29	Soltis	To reflect the State Income Tax effects of all adjustments subject to state income taxes.	$	(399,207.48)
30	Soltis	To provide for the Federal Income Tax effects on all adjustments.	$	(932,330.92)
31	Soltis	To adjust plant in service to reflect terminal treatment of test year reliability projects.	$	20,128,727
32 a	Soltis	To adjust rate base to reflect terminal treatment of post test year reliability projects.	$	19,214,522

The Potomac Edison Company
Maryland Distribution Adjustment Summary
12 Months Ending December 31, 2022

Adjustment Number (Witness)		Description	Maryland Distribution
		Going Level	
b		To adjust CWIP rate base to reflect terminal treatment of test year reliability projects.	$ 7,779,093
33	Soltis	To reflect the depreciation expense effect on accumulated depreciation for the terminal treatment of test year reliability projects.	$ (596,217)
34	Soltis	To reflect the depreciation expense effect on accumulated depreciation for the terminal treatment of post test year reliability projects.	$ (594,527)
35	Soltis	To increase rate base for the Company's material and supplies recorded on books of the service company.	$ 13,191,398
36	Soltis	To reflect the cash working capital requirements on going level adjustments.	$ (158,960)
37	Soltis	To reflect the accumulated deferred income taxes for the terminal treatment of test year reliability projects.	$ (1,737,865)
38	Soltis	To reflect the accumulated deferred income taxes for the terminal treatment of post test year reliability projects.	$ (2,991,255)
39 a	Colflesh	To adjust rate base for service company allocation of plant in service.	$ 25,394,387
39 b	Colflesh	To adjust rate base for service company allocation of reserve.	$ (15,446,379)
39 c	Colflesh	To adjust rate base for service company allocation of ADIT.	$ (1,080,653)
40	Colflesh	To increase rate base for Covid-19 regulatory asset.	$ 6,534,206

The Potomac Edison Company
Maryland Distribution Adjustment Summary
12 Months Ending December 31, 2022

Adjustment Number (Witness)	Description	Maryland Distribution
	Going Level	

The Potomac Edison Company
Maryland Distribution Adjustment Summary
12 Months Ending December 31, 2022

Adjustment Number	(Witness)	Description		Maryland Distribution
		Going Level		
41	Ward	To increase rate base for the Electric Vehicle Portfolio Program regulatory Asset.	$	1,373,661
42	Ashton	To adjust rate base for non-eligible items.	$	(103,159)
		Accounting		
43	Ashton	To adjust test year to remove any out of period items.	$	(938,317)
		Pro Forma		
44	Soltis	To reflect the Pro Forma Revenue Requirement	$	47,492,648
45	Soltis	To reflect the Pro Forma Uncollectible Expense	$	400,682
46	Soltis	To reflect the Pro Forma Regulatory Assessment.	$	131,697
47	Soltis	To reflect the Pro Forma Maryland Gross Receipt Tax.	$	949,853
48	Soltis	To reflect the Pro Forma State Income Tax.	$	3,795,859
49	Soltis	To reflect the Pro Forma Federal Income Tax.	$	8,865,057

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 1
Salaries and Wages Adjustment

Line No.	Description	Reference Account	MD Distribution Amount
	Column (1)	(2)	(3)
1	2022 Salary & Wages Adjustment: Straight-Time Bargaining		
2	Production	920	
3	Transmission	920	
4	Distribution	920	$ 57,152
5	Cust. Accts & Sales	920	
6	A&G	920	
7	Total	920	$ 57,152
8	2022 Salary & Wages Adjustment: Straight-Time NonBargaining		
9	Production	920	
10	Transmission	920	
11	Distribution	920	$ 198,733
12	Cust. Accts & Sales	920	
13	A&G	920	
14	Total	920	$ 198,733
15	Total		$ 255,885

Discussion:

Increase O&M expense to annualize salary increases in 2022.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 months ending December 31, 2022

Adjustment No. 1
Increase Salaries and Wages, Savings Plan & Payroll Taxes
To annualize Salary Increases in 2022

Labor Category	Annual Amount - Direct &		ST Wages **	Wage Increase		Pre-Increase 12/2022		Post-Increase 12/2022			2022 Labor
						Months	Mo. Amount	Months	Mo. Amount	Annualized	PE Adjustment
Bargaining ST	$13,461,789	Local 0102	$ 13,461,789	2.50%	5/1/2022	4	$1,103,425	8	$1,131,011	$13,572,132	$ 110,343
Subtotal Bargaining	$13,461,789		$ 13,461,789				$1,103,425		$1,131,011	$13,572,132	$ 110,343
Non-Bargaining ST	$15,495,570			3.25%	3/1/2022	10	$1,284,341	2	$1,326,082	$15,912,981	$ 417,411
Total	$28,957,359						$2,387,766		$2,457,093	$29,485,113	$ 527,753

Allocations:	MD Allocation Percentages
O&M-D (Distribution O&M)	55.788%
C10 (Avg. Number of Customers)	65.267%
TX60 (Total Payroll Taxes)	57.045%
S&W Distrib PE-MD DX	89.610%

PE Bargaining Straight Time Salary & Wage Adjustment Functionalized

Functional Allocators		Total PE	MD Alloc.			
-0.063%	Production	(69.22)	Direct	-		-
9.029%	Transmission	9,963	Direct	-		
68.769%	Distribution	75,882	O&M-D	42,332	Direct-MD	**42,332**
27.810%	Cust. Accts & Sales	30,686	C10	20,028	S&W Distrib.	**17,947**
-5.545%	A&G	(6,119)	TX60	(3,490)	S&W Distrib.	**(3,128)**
100.000%	TOTAL	$110,343		58,870		**$57,151.87**

PE Nonbargaining Straight Time Salary & Wage Adjustment Functionalized

Functional Allocators		Total PE	MD Alloc.	MD	MD Distrib. Alloc.	**Total MD Distrib**
1.121%	Production	$4,678	Direct	-		-
11.694%	Transmission	48,812				
59.118%	Distribution	246,765	O&M-D	137,664	Direct-MD	**137,664**
3.839%	Cust. Accts & Sales	16,026	C10	10,460	S&W Distrib.	**9,373**
24.228%	A&G	101,129	TX60	57,689	S&W Distrib.	**51,696**
100.000%	TOTAL	$417,411		205,813		**$198,732.96**

TOTAL ADJUSTMENT **$255,884.83**

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 2
Salaries and Wages Adjustment

Line No.	Description	Reference Account	MD Distribution Amount
	Column (1)	(2)	(3)
1	2023 Salary & Wages Adjustment: Straight-Time Bargaining		
2	Production	920	
3	Transmission	920	
4	Distribution	920	$ -
5	Cust. Accts & Sales	920	
6	A&G	920	
7	Total	920	$ -
8	2023 Salary & Wages Adjustment: Straight-Time NonBargaining		
9	Production	920	
10	Transmission	920	
11	Distribution	920	$ 321,723
12	Cust. Accts & Sales	920	
13	A&G	920	
14	Total	920	$ 321,723
15	Total		$ 321,723

Discussion:

Increase O&M expense to annualize salary increases in 2023.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distr bution
Working Papers Supporting Adjustments
12 months ending December 31, 2022

Adjustment No. 2, 4 & 27
Increase Salaries and Wages, Savings Plan & Payroll Taxes
To annualize Salary Increases in 2023

Labor Category	Annual Amount - Direct & ServCo Alloc		Allocated ST Wages **	2022 Wage Increase		Pre-Increase 2022		Post-Increase 2022			2023 Wage Increase	Increase 2023		2023 Labor
						Months	Mo. Amount	Months	Mo. Amount	Annualized		Mo. Amount	Annualized	Adjustment
Bargaining ST	$13,461,789	Local 0102	$ 13,461,789	2 50%	5/1/2022	4	$1,103,425	8	$1,131,011	$13,572,132		$1,131,011	$ 13,572,132	$ -
Subtotal Bargaining	$13,461,789						$1,103,425		$1,131,011	$13,572,132		$1,131,011	$ 13,572,132	$ -
Non-Bargaining ST	$15,495,570			3 25%	3/1/2022	10	$1,284,341	2	$1,326,082	$15,912,981	4 00%	$1,379,125	$ 16,549,500	**$ 636,519**
Total	$28,957,359						$2,387,766		$2,457,093	$29,485,113		$2,510,136	$ 30,121,632	**$ 636,519**

Allocations:	MD Allocation Percentages
O&M-D (Distribution O&M)	55.788%
C10 (Avg. Number of Customers)	65.267%
TX60 (Total Payroll Taxes)	57.045%
S&W Distrib PE-MD DX	89.610%

PE Nonbargaining Straight Time Salary & Wage Adjustment Functionalized

		Total PE	MD Alloc.	MD	MD Distrib. Alloc.
Production	1.121%	$7,134	Direct	-	
Transmission	11.694%	74,434	Direct	-	
Distribution	59.118%	376,298	O&M-D	209,928	Direct-MD
Cust. Accts & Sales	3 839%	24,438	C10	15,950	S&W Distrib.
A&G	24.228%	154,215	TX60	87,972	S&W Distrib.
TOTAL	100.000%	$636,519		**$313,849**	

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 3
Employee Savings Plan Adjustment

Line No.	Description	Reference Account	MD Distribution Amount
	Column (1)	(2)	(3)
1	2022 Savings Plan Adjustment:		
2	Production	926	
3	Transmission	926	
4	Distribution	926	$ 7,677
5	Cust. Accts & Sales	926	
6	A&G	926	
7	Total	926	$ 7,677
8			
9			
10			
11			
12	Total PE's Savings Plan Adjustment on Annualized Salary & Wage Increase found on Adj. 1:		$ 255,885
13			
14			Total MD Distrib
15	Bargaining	3.00%	1,715
16	Non-Bargaining	3.00%	5,962
17	TOTAL		7,677
18			
19	The Company will match 50% of pre-tax contributions (other than Catch-up Contributions) up to the		
20	first 6% of pre-tax Compensation the Participant contributes to the Plan.		

Discussion:

Increase O&M expense to reflect the annualized effect of the expense portion of savings plan.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 4
Employee Savings Plan Adjustment

Line No.	Description	Reference Account	MD Distribution Amount
	Column (1)	(2)	(3)
1	2023 Savings Plan Adjustment:		
2	Production	926	
3	Transmission	926	
4	Distribution	926	$ 9,415
5	Cust. Accts & Sales	926	
6	A&G	926	
7	Total	926	$ 9,415
8			
9			
10			
11			
12	Total PE's Savings Plan Adjustment on Annualized Salary & Wage Increase found on Ad		$ 313,849
13			
14			Total MD Distrib
15	Bargaining	3.00%	
16	Non-Bargaining	3.00%	9,415
17	TOTAL		9,415
18			
19	The Company will match 50% of pre-tax contributions (other than Catch-up Contributions) up to the		
20	first 6% of pre-tax Compensation the Participant contributes to the Plan		

Discussion:

Increase O&M expense to reflect the annualized effect of the expense portion of savings plan.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 5
Adjustment to Distr bution Storm O&M Expenses

Line No.	Description Column (1)	Reference Account (2)	Amount (3)
1	Storm Distr bution O&M Expense for the Twelve Months Ending December 31, 2022	593	$ 2,616,818
2	Average Annual Storm Distribution O&M Expense for the Five Years Ending December 31, 2022	593	2,561,664 (A)
3	Adjustment to Storm Distribution O&M Expense (Line 2 - Line 1)	593	$ (55,154)

Discussion:

To adjust Distribution Storm O&M expenses for the test year to reflect a five year annual average ending December 31, 2022

This adjustment is sponsored by Witness H. E. Ward.

(A) Support Computations:

Line No.	Description	593 Distribution
4	Distribution Storm O&M Expense for the Twelve Months Ended December 31, 2018	$ 2,043,885
5	Distribution Storm O&M Expense for the Twelve Months Ended December 31, 2019	5,643,850
6	Distribution Storm O&M Expense for the Twelve Months Ended December 31, 2020	1,072,305
7	Distribution Storm O&M Expense for the Twelve Months Ended December 31, 2021	1,431,460
8	Distribution Storm O&M Expense for the Twelve Months Ended December 31, 2022	2,616,818
9	Distribution Storm O&M Expense for the 5 Years Ending December 31, 2022 (Line 4 through Line 8)	$ 12,808,318
10	Average Distribution Storm O&M Expense for the Five Years Ending December 31, 2022 (Line 9 divided by 5)	$ 2,561,664

This adjustment is sponsored by Witness H. E. Ward.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 6
Remove Adver ising Expenses

Line No.	Description	Reference Account	Total Company Amount	MD Alloc. Factor	MD Alloc. Factor %	Total MD	MD Distribution Alloc. Factor	MD Distribution Alloc. Factor %	Total MD Distrib	Total MD Dist Adjustment
	Column (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	Distribu ion-Oper Supv & En(	958000	$ 19	GP30	65%	$ 12	Direct	100%	$ 12	$ (12)
2	Distribu ion-Misc Expense	958800	$ 7,920	GP30	65%	$ 5,126	Direct	100%	$ 5,126	$ (5,126)
3	Cust Svc - Cust Assist Exp	990800	$ 6,800	C10	65%	$ 4,438	Direct	100%	$ 4,438	$ (4,438)
4	Cust Svc - Info & Inst Exp	990900	$ 45,245	Direct	1%	$ 45,245	Direct	100%	$ 45,245	$ (45,245)
5	A&G - Outside Services	992300	$ 793	O her	0%	$ -	Direct	100%	$ -	
6	A&G - General Adv Exp	993010	$ 156,193	Direct	1%	$ 57,236	Direct	100%	$ 57,236	$ (11,930)
7	Total		$ 216,969			$ 112,057			$ 112,057	$ (66,751)

Discussion:

To remove certain advertising expenses so that only informational advertising expenses are in the test year per COMAR 20.07.04.08.

This adjustment is sponsored by Witness H. E. Ward.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 7
Postage Increase

Line No	Description Column (1)	Reference Account (2)	Total Company Amount (3)	Allocation Factor - C10 (4)	Maryland Amount (5)
1	Adjusted Customer Accounts Postage Expense	903	$ 1,369,046	65.267%	$ 893,535
2	Customer Accounts Postage Expense Per Books	903	$ 1,271,757	65.267%	$ 830,037
3	Postage increase	903	$ 97,289	65.267%	$ 63,498
4	Decrease due to increase in eBill Enrollments				$ (17,365)
5	Total Adjustment				$ 46,132

Discussion:
Adjust expense for the postage increases effective July 2022 and January 2023, and the impact from eBill Enrollments.

Line No	Details	Amount in Test Year	Going Level Amount	Adjustment Amount
6	6 months ended June 2022	$ 632,551	$ 703,359	$ 70,809
7	6 months ended December 2022	639,206	665,747	$ 26,541
		$ 1,271,757	$ 1,369,106	$ 97,350
8	Price effective January 2022	0.429		
9	Price effective July 2022	0.458		
10	Increase in price versus Jan 2022 rates	0.029		
11	Percent increase in price from Jan 2022 to Jul 2022	6.761%		
12	Price effective January 2023	0.477		
13	Increase in price versus January 2022 rates	0.048		
14	Percent increase in price from Jan 2022 to Jan 2023	11.194%		
15	Increase in price versus July 2022 rates	0.019		
16	Percent increase in price from Jul 2022 to Jan 2023	4.152%		

This adjustment is sponsored by Witness H. E. Ward.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 8
Increase Commission Assessment

Line No.	Description Column (1)	Reference Account (2)	Amount (3)
1	Potomac Edison Maryland Pubic Service Commission Assessment Fees for Twelve Months Ended December 31, 2022	928	$ 1,208,269
2	Potomac Edison Maryland Pubic Service Commission Assessment Fees for FY Starting July 1, 2022	928	1,389,911
3	Increase in Maryland Public Service Commission Assessment Fees (Line 2 - Line 1)	928	$ 181,642
4	Potomac Edison Maryland Distribution Allocation Factor (MDREV Allocator)		23.096%
5	Increase in Regulatory Expense Associated with Maryland Public Service Commission Assessment Fee Rate Effective July 1, 2022 (Line 3 X Line 4)	928	$ 41,952

Discussion:
To reflect increase in Regulatory Commission Expense due to increase in Maryland Commission Assessment Fee.

MD PSC Assessment Fee July 1, 2021 - June 30, 2022	$ 1,026,625
MD PSC Assessment Fee July 1, 2022 - June 30, 2023	$ 1,389,911

This adjustment is sponsored by Witness H. E. Ward.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 9
Medical Insurance Expense Adjustment

Line No.	Description	Reference Account	Amount	MD Alloc. Factor	MD Alloc. Factor %	Total MD	MD Distrib. Alloc. Factor	MD Distrib. Alloc. Factor %	Total MD Distr b
	Column (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	2023 Medical Expense	926	$ 5,883,010						
2	2022 Medical Expense in Test Year	926	$ 5,769,482						
3	Adjustment to O&M Expense (Line 1 Minus Line 2)		$ 113,528	TX60	57.05%	$ 64,762	S&W	89.610%	$ 58,034

Discussion:

Adjust test year O&M expense to reflect going-level Medical expense.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 10
Group Life Insurance Expense Adjustment

Line No.	Description	Reference Account	Amount	MD Alloc. Factor	MD Alloc. Factor %	Total MD	MD Distrib. Alloc. Factor	MD Distrib. Alloc. Factor %	Total MD Distrib
	Column (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	2023 Group Life Insurance Expense	926	$ 63,731						
2	2022 Group Life Insurance Expense in Test Year	926	64,794						
3	Adjustment to O&M Expense (Line 1 Minus Line 2)		$ (1,063)	TX60	57.05%	$ (606)	S&W	89.61%	$ (543)

Discussion:

Adjust test year O&M expense to reflect going-level Group Life Insurance expense.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 11
Pension & OPEB (Gain)/Loss Adjustment

Line No.	Description	Reference Account	Amount	MD Alloc. Factor	MD Alloc. Factor %	Total MD	MD Distrib. Alloc. Factor	MD Distrib. Alloc. Factor %	Total MD Distrib
	Column (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	2022 MTM Adjustment								
2	Potomac Edison								
3	Pension	926	$ 8,216,945						
4	OPEB	926	(367,881)						
5	Total MTM		$ 7,849,064	TX60	57.05%	$ 4,477,501	S&W	89.61%	$ 4,012,311
6	2023 Smoothing Adjustment								
7	Potomac Edison								
8	Pension	926	$ 7,155,041						
9	OPEB	926	282,596						
10	Total Smoothing		$ 7,437,638	TX60	57.05%	$ 4,242,803	S&W	89.61%	$ 3,801,996
11	Increase in Pension and OPEB								$ (210,314)

Discussion:

Remove mark to market adjustment from going level and replace with smoothing adjustment for pension and OPEB.

This adjustment is sponsored by Witness T. M. Ashton.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 12
Pension & OPEB Non-Market to Market Expense Adjustment

Line No.	Description	Reference Account	Amount	MD Alloc. Factor	MD Alloc. Factor %	Total MD	MD Distrib. Alloc. Factor	MD Distrib. Alloc. Factor %	Total MD Distrib	
	Column (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	2022 Non-MTM Pension & OPEB Expense									
2	Potomac Edison									
3	Pension	926	$ (15,450,325)							
4	OPEB	926	(1,771,465)							
5	Total Non-MTM Exp in Test Year		$ (17,221,790)	TX60	57.05%	$ (9,824,176)	S&W	89.61%	$ (8,803,492)	
6	5-Year Average Non-MTM Pension & OPEB Expense									
7	Potomac Edison									
8	Pension	926	$ (12,454,601)							
9	OPEB	926	$ (2,473,360)							
10	Total Average		$ (14,927,961)	TX60	57.05%	$ (8,515,660)	S&W	89.61%	$ (7,630,925)	(A)
11	Adjustment to Pension and OPEB Non-MTM Expense								$ 1,172,567	

Discussion:

Remove non-mark to market expense from going level and replace with 5 year average.

This adjustment is sponsored by Witness T. M. Ashton.

Line No.	(A) Support Computations:	Pension	OPEB	Total
12	Non-MTM O&M Expense for Twelve Months Ended December 31, 2018	$ (6,984,989)	$ (3,735,402)	$ (10,720,391)
13	Non-MTM O&M Expense for Twelve Months Ended December 31, 2019	$ (6,774,473)	$ (2,872,755)	$ (9,647,228)
14	Non-MTM O&M Expense for Twelve Months Ended December 31, 2020	$ (14,345,406)	$ (1,791,624)	$ (16,137,030)
15	Non-MTM O&M Expense for Twelve Months Ended December 31, 2021	$ (18,717,812)	$ (2,195,553)	$ (20,913,365)
16	Non-MTM O&M Expense for Twelve Months Ended December 31, 2022	$ (15,450,325)	$ (1,771,465)	$ (17,221,790)
17	Non-MTM O&M Expense for the 5 Years Ending December 31, 2022 (Line 12 through Line 16)	$ (62,273,005)	$ (12,366,799)	$ (74,639,804)
18	Average Non-MTM O&M Expense for the Five Years Ending December 31, 2022 (Line 17 / 5)	$ (12,454,601)	$ (2,473,360)	$ (14,927,961)

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment Nos. 13 and 19
Rate Case Expense Adjustment

Line No.	Description Column (1)	Reference Account (2)	Amount (3)	Amortization Period (Years) (4)	Total MD Distribution (5)	
1	Customer Notice/Printing/Postage	928	$ 14,126			
2	Employee Expenses	928	19,560			
3	Rate of Return Witness	928	27,500			
4	Depreciation Study Witness	928	386,100			
5	External Legal Fees	928	499,950			
6	Class Cost of Service Study and Rate Design Witness	928	113,316			
7	Lead Lag Study and Cash Working Capital Witness	928	53,618			
8	Electric Vehicle Benefit and Cost Analysis Witness	928	156,500			
8	Totals Deferred Maryland Rate Case Expenses		$ 1,270,670	3	$ 423,557	
9	2023 Maryland Rate Case Expenses in Test Year	928			$ -	
10	Adjustment to Reflect Amortization of Rate Case Expenses (Line 9 - Line 10)	407.4			$ 423,557	Adj# 13
11	Amortization for Recovery of 2018 Maryland Rate Case in Test Year	407.4	$ 11,152		$ 11,152	
12	Adjustment to Remove 2018 Rate Case Amortization from Test Year	407.4	$ (11,152)		$ (11,152)	Adj# 19

Discussion:
To increase going level expenses to recognize amortization of expenses associated with current distribution rate case.
Also, remove test year amortization from recovery of 2018 rate case expense.

This adjustment is sponsored by Witness H. E. Ward.

The Potomac Edison Company
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Adjustment No. 14
Remove COVID-19 Amounts from Test Year

Line No.	Description Column (1)	Reference Account (2)	PE - MD Amount (3)	Distribution Allocator (4)	Allocation Percentage (5)	MD Distribution (6)	MD Distribution Adjustment (7)
1	Operating Company Expenses:						
2	Employee Expenses	588	119.15	Direct	100%	119.15	
3	Materials & Supplies	588	20,721.84	Direct	100%	20,721.84	
4	Postage	903	877.25	Direct	100%	877.25	
5	FMLA Administration	926	61,432.64	A&G - DX	89.61%	55,050.09	
6	Subtotal		83,150.88			76,768.33	
7	Service Company Charges:						
8	Communications & Advertising	923	-	A&G - DX	89.61%	-	
9	Customer Service Technology	923	2,286.35	A&G - DX	89.61%	2,048.81	
10	Customer Accounting & Billing	923	76,308.37	A&G - DX	89.61%	68,380.30	
11	COVID Supply Purchases	923	3,886.65	A&G - DX	89.61%	3,482.85	
12	FMLA Administration	923	5,386.43	A&G - DX	89.61%	4,826.81	
13	Information Technology	923	69.99	A&G - DX	89.61%	62.72	
14	Other	923	5,196.34	A&G - DX	89.61%	4,656.47	
15	Subtotal		93,134.13			83,457.95	
16	Incremental Uncollectibles Expense Accrual	904	2,103,093.00	Direct	100%	2,103,093.00	
17	Total		2,279,378.01			2,263,319.27	
	Total O&M in Test Year		2,279,378.01			2,263,319.27	$ (2,263,319.27)

Discussion:

Adjustment removes Covid-19 amounts from the test year.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
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Adjustment No. 15
Adjust to Remove Service Company Carrying Charges from Test Year

Line No.	FERC Account	Description		Amount
1	923	Service Company Carrying Charges in Test Year	$	1,872,349
2		Jurisdictional Allocator GP01 - allocate to MD		60.90%
3		FE ServCo allocated to PE - MD	$	1,140,244
4		Distribution Allocator S&W		89.61%
5		FE ServCo allocated to PE - MD Distribution	$	1,021,778
6	923	Remove PE-MD Distribution Service Company Carrying Charges	$	(1,021,778)

Discussion:
The FE Service Company charges Potomac Edison Carrying Charges which reimburse the Service Company for the cost of having the plant on their books, including ADITs, Interest, and a Return. This adjustment removed the carrying charges from the test year.

Line No.	FERC Account	Description		Amount
7	923	Service Company Depreciation & Amortization Expense in Test Year	$	3,154,879
8		Jurisdictional Allocator GP01 - allocate to MD		60.90%
9		FE ServCo allocated to PE - MD	$	1,921,293
10		Distribution Allocator S&W		89.61%
11		FE ServCo allocated to PE - MD Distribution	$	1,721,680
12	923	Remove PE-MD Distribution Depreciation & Amortization Expenses	$	(1,721,680)

Discussion:
Depreciation expense from the Service Company is allocated and billed to Potomac Edison in FERC account 923 Service Company Depreciation expenses are calculated on Service Company Depreciation Rates, which may not the same as Potomac Edistons Depreciation Rates, so the amount billed to Potomac Edison in acocunt 923 relate to Service Company depreciation and amortization is removed.

Depreciation expense on Potomac Edison - MD's allocated share of Service Company Plant Assets will be recalculated based on PE-Maryland Depreciation rates and added back to the test year on Adjustment 21.

This adjustment is sponsored by Witness S. M. Colflesh.

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Adjustment No. 16
Adjust Depreciation Expense to Reflect New Depreciation Rates

Line No.	Description	Reference Account	MD Juris Amount	Allocator	
	Column (1)	(2)	(3)		
1	Depreciation Expense - New Rates	403	$ 31,311,414		
2	Depreciation Expense - Current Rates	403	28,456,194		
3	Increase in Depreciation Expense (Line 1 minus Line 2)	403	$ 2,855,219		
4	Breakdown by Function			Allocator	
5	Intangible Plant		$ (1,178,500)	S&W	89.61%
6	Distribution		4,251,230	Direct	100.00%
7	General		(217,511)	S&W	89.61%
8	Total		$ 2,855,219		

Discussion:
Adjust depreciation expense to reflect new proposed depreciation rates.

This adjustment is sponsored by Witness H. E. Ward.

MD Distribution
$ (1,056,059)
4,251,230
(194,912)
$ 3,000,258

The Potomac Edison Company
Maryland Distribution
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Adjustment No. 17
Depreciation Expense on Terminal Treatment of Reliability Projects

Line No.	Description	Reference Account	MD Depreciation Rates	Amount	MD Alloc. Factor	MD Alloc. Factor %	Total MD	MD Distrib. Alloc. Factor	MD Distrib. Alloc. Factor %	Total MD Distrib
	Column (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Misc. Intangible Plant	30300	7.21%	$ 63,637	GP60	57.045%	$ 36,302	S&W	89.610%	$ 32,530
2	Structures, Improvements	36110	1.27%	1,144	Direct		1,144	Direct		1,144
3	Station Equipment	36200	1.35%	33,677	Direct		33,677	Direct		33,677
4	Poles, Towers And Fixtures	36400	1.81%	17,443	Direct		17,443	Direct		17,443
5	Overhead Conductor, Devices	36500	2.02%	101,656	Direct		101,656	Direct		101,656
6	Clearing, Grading of Land	36510	1.25%	620	Direct		620	Direct		620
7	Underground Conduit	36600	1.62%	6,596	Direct		6,596	Direct		6,596
8	Underground Conductor, Devices	36700	3.23%	232,230	Direct		232,230	Direct		232,230
9	Line Transformers	36800	1.83%	45,122	Direct		45,122	Direct		45,122
10	Structures, Improvements	39010	1.36%	171	Direct		171	S&W	89.610%	153
11	Data Processing Equipment	39120	17.42%	193,216	GP35	61.106%	118,067	S&W	89.610%	105,800
12	Communication Equipment	39700	5.26%	35,148	GP35	61.106%	21,477	S&W	89.610%	19,246
13	Totals			$ 730,660			$ 614,504			$ 596,217
									Intangible	$ 32,530
									Distribution	438,488
	Discussion:								General	125,199

To reflect depreciation expense on terminal treatment of reliability projects completed during the test year.

The Potomac Edison Company
Maryland Distribution
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Adjustment No. 18
Depreciation Expense on Terminal Treatment of Reliability Projects - Post Test Year, 6-Months Ended June 2023

Line No.	Description	Reference Account	MD Depreciation Rates		Amount	MD Alloc. Factor	MD Alloc. Factor %		Total MD	MD Distrib. Alloc. Factor	MD Distrib. Alloc. Factor %		Total MD Distrib
	Column (1)	(2)	(3)		(4)	(5)	(6)		(7)	(8)	(9)		(10)
1	Misc. Intangible Plant	30300	7.21%	$	68,331	GP60	57.045%	$	38,979	S&W	89.610%	$	34,930
2	Structures, Improvements	36110	1.27%		1,100	Direct			1,100	Direct			1,100
3	Station Equipment	36200	1.35%		33,165	Direct			33,165	Direct			33,165
4	Poles, Towers And Fixtures	36400	1.81%		35,239	Direct			35,239	Direct			35,239
5	Overhead Conductor, Devices	36500	2.02%		27,850	Direct			27,850	Direct			27,850
6	Clearing, Grading of Land	36510	1.25%		35,318	Direct			35,318	Direct			35,318
7	Underground Conduit	36600	1.62%		20,692	Direct			20,692	Direct			20,692
8	Underground Conductor, Devices	36700	3.23%		199,152	Direct			199,152	Direct			199,152
9	Line Transformers	36800	1.83%		35,969	Direct			35,969	Direct			35,969
10	Terminal CWIP W. Jefferson & Myersville		2.09%		162,583	Direct			162,583	Direct			162,583
11	Structures, Improvements	39010	1.36%		9,521	Direct			9,521	S&W	89.610%		8,531
12	Totals			$	628,918			$	599,566			$	594,527
											Intangible	$	34,930
											Distr bution		388,483
	Discussion:										General		8,531
											CWIP		162,583

To reflect depreciation expense on terminal treatment of reliability projects anticipated to be completed prior to start of hearings.

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Maryland Distribution
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Adjustment Nos. 13 and 19
Rate Case Expense Adjustment

Line No.	Description	Reference Account	Amount	Amortization Period (Years)	Total MD Distribution	
	Column (1)	(2)	(3)	(4)	(5)	
1	Customer Notice/Printing/Postage	928	$ 14,126			
2	Employee Expenses	928	19,560			
3	Rate of Return Witness	928	27,500			
4	Depreciation Study Witness	928	386,100			
5	External Legal Fees	928	499,950			
6	Class Cost of Service Study and Rate Design Witness	928	113,316			
7	Lead Lag Study and Cash Working Capital Witness	928	53,618			
8	Electric Vehicle Benefit and Cost Analysis Witness	928	156,500			
8	Totals Deferred Maryland Rate Case Expenses		$ 1,270,670	3	$ 423,557	
9	2023 Maryland Rate Case Expenses in Test Year	928			$ -	
10	Adjustment to Reflect Amortization of Rate Case Expenses (Line 9 - Line 10)	407.4			$ 423,557	Adj# 13
11	Amortization for Recovery of 2018 Maryland Rate Case in Test Year	407.4	$ 11,152		$ 11,152	
12	Adjustment to Remove 2018 Rate Case Amortization from Test Year	407.4	$ (11,152)		$ (11,152)	Adj# 19

Discussion:
To increase going level expenses to recognize amortization of expenses associated with current distribution rate case.
Also, remove test year amortization from recovery of 2018 rate case expense.

This adjustment is sponsored by Witness H. E. Ward.

The Potomac Edison Company
Maryland Distribution
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Adjustment No. 20
Adjust to add Service Company Depreciation and Amortization at Maryland Rate to Test Year

Line No.	Account	DESCRIPTION	13 Mo Avg Plant In Service Balance as of Dec 31, 2022	Maryland Depreciation Rate		Depreciation Expense based on MD Rates
1	301	Organization (Fully Amortized)	49,344	0.00%	$	-
2	303	Miscellaneous Intangible Plant (Software)	542,813,167	7.21%	$	39,136,829
3	389	Land & Land Rights (non-depreciable)	187,282	0.00%	$	-
4	390	Structures & Improvements	50,241,398	1.36%	$	683,283
5	390	Leasehold Improvements	28,919,388	1.36%	$	393,304
6	391.1	Office Furniture & Equipment	15,072,135	3.68%	$	554,655
7	391.2	Office Equipment - Information Systems	154,561,518	17.42%	$	26,924,616
8	392	Transportation Equipment	6,109,892	2.52%	$	153,969
9	393	Stores Equipment	17,057	1.15%	$	196
10	394	Tools, Shop & Garage Equipment	300,960	4.60%	$	13,844
11	395	Laboratory Equipment	733,941	1.85%	$	13,578
12	396	Power Operated Equipment	438,758	-0.30%	$	(1,316)
13	397	Communication Equipment	154,401,555	5.26%	$	8,121,522
14	398	Miscellaneous Equipment	3,597,174	0.59%	$	21,223
15	399	Asset Retirement Costs for General Plant	40,721	0.00%	$	-
16		SUB - TOTAL	957,484,291			76,015,703
17		Multifactor allocation factor from SC00 to PE for Depr Expense				4.86%
18		Allocated to PE - Total Company				3,694,363
19		Jurisdictional Allocation Factor GP01 - MI				60.90%
20		Allocated to PE- Maryland				2,249,834
21		Distribution allocator - Salaries & Wages				89.61%
22	403-404	Depreciation expense allocated to PE Maryland Distr bution based on MD Deprecia			$	2,016,088
				Intangible	$	1,037,987
				General	$	978,101

Discussion:
Depreciation expense on Potomac Edison - MD's allocated share of Service Company Plant Assets has been recalculated based on PE-MD's Depreciation rates and added back to the test year in account 403 / 404.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
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Adjustment No. 21
Remove Conservation Voltage Reduction Program Amortization

Line No.	Description	Reference Account	MD Distribution Amount
	Column (1)	(2)	(3)
1	CVR Amortization in Test Year	407.4	$ 33,050
2	Adjustment to Remove CVR Amortization	407.4	(33,050)

Discussion:

Adjustment to remove amortization of Conservation Voltage Reduction ("CVR") recovery in test year.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
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Adjustment No. 22
COVID-19 Deferral

Line No.	Description	Reference Account	Total MD Distribution Amount
	Column (1)	(2)	(3)
1	COVID-19 Deferrals in Test Year	407.4	$ (2,263,319)
2	Adjustment to remove COVID-19 Deferrals	407.4	$ 2,263,319

Discussion:

Adjustment to remove regulatory credits related to deferral of COVID-19 incremental costs in 2022 test year.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
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Adjustment No. 23
COVID-19 Amortization Adjustment

Line No.	Description	Reference Account	PE - MD Amount	Distribution Allocator	Allocation Percentage	MD Distribution	Amortization Period (Years)	Total MD Distribution
	Column (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Operating Company Expenses:							
2	Employee Expenses	588	7,587.12	Direct	100%	7,587.12		
3	Materials & Supplies	588	78,576.57	Direct	100%	78,576.57		
4	Misc. Leases & Rentals	588	249,546.38	Direct	100%	249,546.38		
5	Outside Contractors	923	8,356.07	A&G - DX	89.61%	7,487.91		
6	Postage	903	5,698.53	Direct	100%	5,698.53		
7	FMLA Administration	926	290,329.24	A&G - DX	89.61%	260,165.44		
8	Informational Advertising	909	2,765.02	Direct	100%	2,765.02		
9	Pandemic Recognition Awards	588	690,452.48	Direct	100%	690,452.48		
10	Over ime Labor	588	795.03	Direct	100%	795.03		
11	Subtotal		1,334,106.44			1,303,074.48		
12	Service Company Charges:							
13	Communications & Advertising	923	124,384.92	A&G - DX	89.61%	111,461.93		
14	Customer Service Technology	923	112,456.95	A&G - DX	89.61%	100,773.22		
15	Customer Accounting & Billing	923	169,187.12	A&G - DX	89.61%	151,609.40		
16	COVID Supply Purchases	923	89,702.65	A&G - DX	89.61%	80,382.98		
17	FMLA Administration	923	45,947.24	A&G - DX	89.61%	41,173.54		
18	Information Technology	923	13,960.28	A&G - DX	89.61%	12,509.87		
19	Other	923	27,151.93	A&G - DX	89.61%	24,330.98		
20	Subtotal		582,791.09			522,241.92		
21	Late Payment Fees Waived (Distribution Only)							
22	Residential	450	470,537.69	Direct	100%	470,537.69		
23	Commercial	450	110,401.48	Direct	100%	110,401.48		
24	Industrial	450	25,749.38	Direct	100%	25,749.38		
25	St Lighting	450	693.84	Direct	100%	693.84		
26	Subtotal		607,382.39			607,382.39		
27	Reconnection fees not charged	451	216.00	Direct	100%	216.00		
28	Incremental Uncollec ibles Expense Accrual	904	4,827,313.97	Direct	100%	4,827,313.97		
29	Total		7,351,809.89			7,260,228.76	5	$1,452,046

Discussion:
To increase going level expenses to recognize amortization of expenses associated with recovery of incremental COVID-19 costs.

This adjustment is sponsored by Witness S. M. Colflesh.

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Adjustment No. 24
Increase O&M Expense for Electric Vehicle Portfolio Program Regulatory Asset

Line No.	Description	Reference Account	Amount
	Column (1)	(2)	(3)
1	Electric Vehicle Regulatory Asset at 12/31/22	182207	$ 1,526,290
2	Amortize Over Years		5
3	Increase to Expense Per Year (Line 1 / Line 2)		$ 305,258

Discussion:

Adjustment to increase O&M expense to reflect recovery of Electric Vehicle regulatory asset.

This adjustment is sponsored by Witness H. E. Ward.

The Potomac Edison Company
Maryland Distribution
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Adjustment No. 25
Remove Electric Vehicle Portfolio Program Deferral in Test Year

Line No.	Description	Reference Account		Amount
	Column (1)	(2)		(3)
1	Test Year Electric Vehicle Deferral in Regulatory Credit	407.4	$	(527,034)
2	Adjustment to remove Regulatory Credit		$	527,034

Discussion:

Adjustment to remove regulatory credit in test year related to Electric Vehicle deferral.

This adjustment is sponsored by Witness H. E. Ward.

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Maryland Distribution
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Adjustment No. 26
Payroll Taxes Salaries and Wages Adjustment

Line No.	Description		Reference Account	MD Distribution Amount
	Column (1)		(2)	(3)
	2022 FICA Adjustment:			
1	Production		408.1	
2	Transmission		408.1	
3	Distribution		408.1	$ 19,575
4	Cust. Accts & Sales		408.1	
5	A&G		408.1	
6	Total		408.1	$ 19,575
7				
8				
9				
10	Adjustment on Annualized Salary & Wage Increase found on Adj. 1:			$ 255,885
11				
12	Calculation of Employer Portion of FICA tax on above Increase:			Total MD Distrib
13		Bargaining	7.65%	4,372
14		Non-Bargaining	7.65%	15,203
15		TOTAL		$ 19,575

Discussion:

Increase O&M expense to reflect the annualized effect of the expense portion of FICA payroll tax increases.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
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Adjustment No. 27
Payroll Taxes Salaries and Wages Adjustment

Line No.	Description		Reference Account	MD Distribution Amount
	Column (1)		(2)	(3)
	2023 FICA Adjustment:			
1	Production		408.1	
2	Transmission		408.1	
3	Distribution		408.1	$ 24,612
4	Cust. Accts & Sales		408.1	
5	A&G		408.1	
6	Total		408.1	$ 24,612
7				
8				
9				
10	Adjustment on Annualized Salary & Wage Increase found on Adj. 2:			$ 321,723
11				
12	Calculation of Employer Portion of FICA tax on above Increase:			Total MD Distrib
13		Bargaining	7.65%	-
14		Non-Bargaining	7.65%	24,612
15		TOTAL		$ 24,612

Increase O&M expense to reflect the annualized effect of the expense portion of FICA payroll tax increases.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
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Adjustment No. 28
Interest Synchronization

Line No.	Description	Reference Account	MD Distribution Amount
	Column (1)	(2)	(3)
1	Per Books Rate Base		$ 647,618,240
2	Rate Base Adjustments [1]		71,065,938
3	Adjusted Rate Base		$ 718,684,179
4	Interest Component of Rate of Return		1.867%
5	Adjusted Interest	427	$ 13,420,137
7	Allocated Interest	427	15,395,076
9	Interest Adjustment		$ (1,974,939)
10	Impact on State Taxable Income		$ 1,974,939
11	State Income Tax Rate		8.25%
12	State Income Taxes	409.100	$ 162,932
13	Federal Taxable Income		$ 1,812,007
14	Federal Income Tax Rate		21%
15	Federal Income Taxes	409.149	$ 380,521
16	State and Federal Income Tax Impact on Income		$ (543,454)

Discussion:

To reflect the State and Federal income tax effects of substituting the amount of interest implicit in the capital structure used in the Company's rate of return request for book interest expense.

[1] Excludes cash working capital change in cash requirement from going level adjustments.

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Adjustment No. 29
State Income Taxes on Going Level Adjustments

Line No.	Going Level Adjustment No.	Description		MD Distribution Taxable Income
		Column (1)		(2)
1	1	Salaries and Wages-Test Year		(255,885)
1	2	Salaries and Wages-2023		(321,723)
2	3	Employee Savings Plan-Test Year		(7,677)
2	4	Employee Savings Plan-2023		(9,415)
3	5	Storm Damage		55,154
4	6	Remove Advertising Expense		66,751
5	7	Increase Postage Expense		(46,132)
6	8	Commission Assessment Increase		(41,952)
7	9	Medical Insurance Expense		(58,034)
8	10	Group Life Insurance Expense		543
9	11	Pension/OPEB Expense MTM Related		210,314
10	12	Pension/OPEB Expense Non-MTM Related		(1,172,567)
10	13	Rate Case Expense		(423,557)
11	14	O&M Expense Recovered in Covid-19 Deferral		2,263,319
12	15	Service Company Charges		2,743,458
13	16	Depreciation Expense New Rates		(3,000,258)
14	17	Depreciation Expense on Test Year Reliability Projects		(596,217)
15	18	Depreciation Expense on Post Test Year Reliability Projects		(594,527)
16	19	Rate Case Expense Amortization		11,152
17	20	Depr Expense on Service Company Alloc of Rate Base		(2,016,088)
16	21	Conservation Voltage Reduction (407.4)		33,050
17	22	Covid-19 Regulatory Credit Removal (407.4)		(2,263,319)
18	23	Covid-19 Regulatory Asset Amortization (407.3)		(1,452,046)
19	24	Electric Vehicle Regulatory Asset Amortization (407.3)		(305,258)
20	25	Electric Vehicle Regulatory Credit Removal (407.4)		(527,034)
21	26	Payroll Taxes Salaries and Wages-Test Year		(19,575)
22	27	Payroll Taxes Salaries and Wages-2023		(24,612)
23	28	Interest Synchronization		1,974,939
24	43	Accounting Adjustments		938,317
25		Total Maryland State Taxable Income	$	(4,838,879)
26		Maryland State Income Tax Rate		8.25%
27		Maryland State Income Tax on going level adjustments	$	(399,207)
28		Discussion:		
29		To determine the effect of the going level adjustments on Maryland State Income Tax.		

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Adjustment No. 30
Federal Income Tax on Going Level Adjustments

Line No.	Description	MD Distribution Taxable Income
	Column (1)	(2)
1	State Taxable Income from Adjustment No. 29	$ (4,838,879)
2		
3	Adjustment No. 29 - Maryland State Income Tax on going level adjustments	(399,207)
4		
5	Federal Taxable Income	$ (4,439,671)
6		
7	Federal Income Tax Rate	21.00%
8		
9	Federal Income Taxes on going level adjustments	$ (932,331)

Discussion:

To calculate effect of the going level adjustments on Federal Income Tax.

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Adjustment No. 31
Terminal Treatment of Reliability Projects

Line No.	Description	Reference Account	Terminal Treatment Amount	MD Alloc. Factor	MD Alloc. Factor %	Total MD	MD Distrib. Alloc. Factor	MD Distrib. Alloc. Factor %	Total MD Distrib
	Column (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Misc. Intangible Plant	30300	$ 882,622	GP60	57.045%	$ 503,492	S&W	89.610%	$ 451,182
2	Structures, Improvements	36110	90,045	Direct		90,045	Direct		90,045
3	Station Equipment	36200	2,494,574	Direct		2,494,574	Direct		2,494,574
4	Poles, Towers And Fixtures	36400	963,718	Direct		963,718	Direct		963,718
5	Overhead Conductor, Devices	36500	5,032,496	Direct		5,032,496	Direct		5,032,496
6	Clearing, Grading of Land	36510	49,577	Direct		49,577	Direct		49,577
7	Underground Conduit	36600	407,157	Direct		407,157	Direct		407,157
8	Underground Conductor, Devices	36700	7,189,781	Direct		7,189,781	Direct		7,189,781
9	Line Transformers	36800	2,465,681	Direct		2,465,681	Direct		2,465,681
10	Structures, Improvements	39010	12,584	Direct		12,584	S&W	89.610%	11,277
11	Data Processing Equipment	39120	1,109,163	GP35	61.106%	677,764	S&W	89.610%	607,348
12	Communication Equipment	39700	668,211	GP35	61.106%	408,316	S&W	89.610%	365,894
13	Total		$ 21,365,607			$ 20,295,184			$ 20,128,727

Discussion:

To reflect terminal treatment of reliability projects completed during the test year.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments

Adjustment No. 32
Terminal Treatment of Reliability Projects - Post Test Year, 6-Months Ended June 2023

Line No.	Description	Reference Account	Terminal Treatment Amount	MD Alloc. Factor	MD Alloc. Factor %	Total MD	MD Distrib. Alloc. Factor	MD Distrib. Alloc. Factor %	Total MD Distrib	
	Column (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	Misc. Intangible Plant	30300	$ 947,723	GP60	57.045%	$ 540,629	S&W	89.610%	$ 484,460	
2	Structures, Improvements	36110	86,641	Direct		86,641	Direct		86,641	
3	Station Equipment	36200	2,456,647	Direct		2,456,647	Direct		2,456,647	
4	Poles, Towers And Fixtures	36400	1,946,883	Direct		1,946,883	Direct		1,946,883	
5	Overhead Conductor, Devices	36500	1,378,690	Direct		1,378,690	Direct		1,378,690	
6	Clearing, Grading of Land	36510	2,825,427	Direct		2,825,427	Direct		2,825,427	
7	Underground Conduit	36600	1,277,274	Direct		1,277,274	Direct		1,277,274	
8	Underground Conductor, Devices	36700	6,165,682	Direct		6,165,682	Direct		6,165,682	
9	Line Transformers	36800	1,965,502	Direct		1,965,502	Direct		1,965,502	
10	Terminal CWIP W. Jefferson & Myersville		7,779,093	Direct		7,779,093	Direct		7,779,093	
11	Structures, Improvements	39010	700,047	Direct		700,047	S&W	89.610%	627,315	
12	Totals		$ 27,529,609			$ 27,122,515		Without CWIP	$ 19,214,522	a
								CWIP	7,779,093	b

Discussion:

To reflect terminal treatment of post test year reliability projects anticipated to be completed prior to start of hearings.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 33
Accumulated Depreciation on Terminal Treatment of Reliability Projects

Line No.	Description	Reference Account	Terminal Treatment Amount	MD Alloc. Factor	MD Alloc. Factor %	Total MD	MD Distrib. Alloc. Factor	MD Distrib. Alloc. Factor %	Total MD Distrib
	Column (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Misc. Intangible Plant	30300	$ 63,637	GP60	57.045%	$ 36,302	S&W	89.610%	$ 32,530
2	Structures, Improvements	36110	1,144	Direct		1,144	Direct		1,144
3	Station Equipment	36200	33,677	Direct		33,677	Direct		33,677
4	Poles, Towers And Fixtures	36400	17,443	Direct		17,443	Direct		17,443
5	Overhead Conductor, Devices	36500	101,656	Direct		101,656	Direct		101,656
6	Clearing, Grading of Land	36510	620	Direct		620	Direct		620
7	Underground Conduit	36600	6,596	Direct		6,596	Direct		6,596
8	Underground Conductor, Devices	36700	232,230	Direct		232,230	Direct		232,230
9	Line Transformers	36800	45,122	Direct		45,122	Direct		45,122
10	Structures, Improvements	39010	171	Direct		171	S&W	89.610%	153
11	Data Processing Equipment	39120	193,216	GP35	61.106%	118,067	S&W	89.610%	105,800
12	Communication Equipment	39700	35,148	GP35	61.106%	21,477	S&W	89.610%	19,246
13	Total		$ 730,660			$ 614,504			$ 596,217

Discussion:

To reflect accumulated depreciation on terminal treatment of test year reliability projects.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments

Adjustment No. 34
Accumulated Depreciation on Terminal Treatment of Reliability Projects - Post Test Year, 6-Months Ended June 2023

Line No.	Description	Reference Account	Terminal Treatment Amount	MD Alloc. Factor	MD Alloc. Factor %	Total MD	MD Distrib. Alloc. Factor	MD Distrib. Alloc. Factor %	Total MD Distrib
	Column (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Misc. Intangible Plant	30300	$ 68,331	GP60	57.045%	$ 38,979	S&W	89.610%	$ 34,930
2	Structures, Improvements	36110	1,100	Direct		1,100	Direct		1,100
3	Station Equipment	36200	33,165	Direct		33,165	Direct		33,165
4	Poles, Towers And Fixtures	36400	35,239	Direct		35,239	Direct		35,239
5	Overhead Conductor, Devices	36500	27,850	Direct		27,850	Direct		27,850
6	Clearing, Grading of Land	36510	35,318	Direct		35,318	Direct		35,318
7	Underground Conduit	36600	20,692	Direct		20,692	Direct		20,692
8	Underground Conductor, Devices	36700	199,152	Direct		199,152	Direct		199,152
9	Line Transformers	36800	35,969	Direct		35,969	Direct		35,969
10	Terminal CWIP W. Jefferson & Myersville		162,583	Direct		162,583	Direct		162,583
11	Structures, Improvements	39010	9,521	Direct		9,521	S&W	89.610%	8,531
12	Totals		$ 628,918			$ 599,566			$ 594,527

Discussion:

To reflect accumulated depreciation on terminal treatment of post test year reliability projects anticipated to be completed prior to start of hearings.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 35
Materials and Supplies Adjustment

Line No.	Description Column (1)	Reference Account (2)	MD Distribution Amount (3)
1	Distribution Inventory located in Maryland (excluding centralized Meters)	154	$ 12,711,795
2	Allocation of Bethel Meters	154	252,444
3	Allocation of North Street Meters	154	22,286
4	Allocation of Connellsville Meters	154	204,873
5	Maryland Distribution Ending Inventory Value - 13 Mo. Avg.		$ 13,191,398

Discussion:

Reflect 13-month average distribution inventory allocated to PE Maryland held by FE Service Company.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 36
Cash Working Capital on Going-Level Adjustments

Line No.	Description Column (1)	Electric Distribution (2)	Going Level Adjustments (3)	Going Level Electric Distribution (4)
1	Operating Revenues	$ 138,842,885		$ 138,842,885
2	Operating Revenue Adjustments		$ -	-
3	Adjusted Operating Revenues			$ 138,842,885
4	Operating & Maintenance Expenses	59,657,983	(3,002,598)	$ 56,655,385
5	Taxes - Other	30,563,131	44,187	30,607,318
6	Income Taxes			
7	Interest Expense	15,395,076	(1,974,939)	13,420,137
8	Total	$ 105,616,191	$ (4,933,350)	$ 100,682,840
9	Daily Cash Requirement (Line 8 /365)	$ 289,359	$ (13,516)	$ 275,843
10	Revenue Lag minus Expense Lead (Days)	11.760845	11.760845	11.760845
11	Cash Requirement	$ 3,403,111	$ (158,960)	$ 3,244,151
12	Change in Cash Requirement from going level adjustments		$ (158,960)	

Discussion:

To reflect the change in cash working capital requirement from the previously listed going level adjustments.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 37
Accumulated Deferred Income Taxes on Terminal Treatment of Reliability Projects

Line No.	Description	Reference Account	Total MD Distrib
	Column (1)	(2)	(3)
1	Misc. Intangible Plant	30300	$ (49,870)
2	Structures, Improvements	36110	(7,505)
3	Station Equipment	36200	(219,110)
4	Poles, Towers And Fixtures	36400	(83,428)
5	Overhead Conductor, Devices	36500	(432,748)
6	Clearing, Grading of Land	36510	(4,368)
7	Underground Conduit	36600	(35,460)
8	Underground Conductor, Devices	36700	(594,314)
9	Line Transformers	36800	(213,315)
10	Structures, Improvements	39010	(950)
11	Data Processing Equipment	39120	(60,730)
12	Communication Equipment	39700	(36,067)
13	Total		$ (1,737,865)

Discussion:

To reflect accumulated deferred income taxes on terminal treatment of test year reliability projects.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments

Adjustment No. 38
Accum Deferred Income Taxes on Terminal Treatment of Reliability Projects - Post Test Year, 6-Months Ended June 2(

Line No.	Description	Reference Account	Total MD Distrib
	Column (1)	(2)	(3)
1	Misc. Intangible Plant	30300	$ (53,548)
2	Structures, Improvements	36110	(7,221)
3	Station Equipment	36200	(215,779)
4	Poles, Towers And Fixtures	36400	(168,539)
5	Overhead Conductor, Devices	36500	(118,555)
6	Clearing, Grading of Land	36510	(248,948)
7	Underground Conduit	36600	(111,240)
8	Underground Conductor, Devices	36700	(509,661)
9	Line Transformers	36800	(170,043)
10	Terminal CWIP W. Jefferson & Myersville		(1,334,864)
11	Structures, Improvements	39010	(52,857)
12	Totals		$ (2,991,255)

Discussion:

To reflect accumulated deferred income taxes on terminal treatment of post test year reliabiltiy projects.

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The Potomac Edison Company
Maryland Distr bution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 39a and 39b
Adjust to allocate share of Plant in Service on Service Company Books to MD Rate Base

Line No.	FERC Account	Net Plant in Service on Service Company books	13 month Avg (Dec 2021 through Dec 2022) Book Cost	Depr Reserve	Net Book Value
1	30100	Intangible plant - organizational	$ 49,344	$ 49,344	$ -
2	30300	Intangible plant - software	542,813,167	412,772,931	130,040,236
3	38910	Land and land rights	187,282	-	187,282
4	39010	Structures and Improvements (Buildings)	49,124,866	32,167,777	16,957,088
5	39020	Structure & Improvements (grading, clearing, driveways, concrete, other outside)	1,116,533	1,116,177	356
6	39030	Leasehold Improvements	28,919,388	12,428,023	16,491,365
7	39110	Office Furniture and Fixtures	15,072,135	10,658,498	4,413,637
8	39120	Office Furniture and Fixtures - Information Systems	154,561,518	45,178,252	109,383,266
9	39200	Transportation equipment	6,109,892	2,163,649	3,946,243
10	39300	Stores equipment	17,057	9,966	7,091
11	39400	Tools, shop and garage equipment	300,960	29,309	271,651
12	39500	Laboratory equipment	733,941	65,358	668,583
13	39600	Power operated equipment	438,758	210,190	228,568
14	39700	Communication equipment	154,355,193	63,707,125	90,648,068
15	39710	Communication equipment - F beroptics	46,361	37,240	9,121
16	39800	Miscellanaeous equipment	3,597,174	1,774,232	1,822,942
17	39910	Asset Retirement Costs for General Plant	40,721	30,941	9,780
18		Total Service Company Plant in Service	$ 957,484,291	$ 582,399,012	$ 375,085,279
19		2022 ServCo Multi Factor-All - % To Potomac Edison	4.86%	4.86%	4.86%
20		FE ServCo allocated to PE	$ 46,533,737	$ 28,304,592	$ 18,229,145
21		Jurisdictional Allocator GP01 - allocate to MD	60.90%	60.90%	60.90%
22		FE ServCo allocated to PE - MD	$ 28,338,633	$ 17,237,246	$ 11,101,388
23		Distributon Allocator S&W	89.61%	89.61%	89.61%
24		FE ServCo allocation to PE - MD Distribution Rate Base	25,394,387	15,446,379	9,948,007
			a.	b.	

Discussion:
Adjustment adds an allocated share of Plant Assets that are booked to the Service Company but used by Potomac Edison to Potomac Edison Rate base.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 39c
Adjustment to Allocate Share of ADITs on Service Company Books to MD Rate Base

Line No.	FERC Account	Accumulated Deferred Income Tax		13 month Avg (Dec 2021 through Dec 2022) Book Value
1	190 & 282	Total Service Company Property related ADIT's	$	(40,745,546)
2		2022 ServCo Multi Factor-All - % To Potomac Edison		4.86%
3		FE ServCo allocated to PE	$	(1,980,234)
4		Jurisdictional Allocator GP01 - allocate to MD		60.90%
5		FE ServCo allocated to PE - MD	$	(1,205,945)
6		Distribution Allocator S&W		89.61%
7	190 & 282	FE ServCo allocated to PE - MD Distribution Rate Base	$	(1,080,653)

Discussion:
Adjustment adds an allocated share of property-related ADIT's booked to the Service Company to Potomac Edison rate base.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 40
Covid-19 Regulatory Asset Adjustment

Line No.	Description	Reference Account	Total MD Distribution Amount
	Column (1)	(2)	(3)
1	Covid-19 Regulatory Asset at December 31, 2022	182.3	$ 7,260,229
2	Accumulated Amortization Mid Year Convention	182.3	$ 726,023
3	Unamortized Balance to Rate Base		$ 6,534,206

Discussion:
Adjust rate base to add regulatory asset for Covid-19.

This adjustment is sponsored by Witness S. M. Colflesh.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 41
Maryland Electric Vehicle Portfolio Program Regulatory Asset to Rate Base

Line No.	Description	Reference Account	Total MD Distribution Amount
	Column (1)	(2)	(3)
1	Electric Vehicle Program Regulatory Asset at December 31	182.207	$ 1,526,290
2	Amortization Period in Years		5
3	Going Level Recovery in Rates	407.3	$ 305,258
4	Accumulated Amortization Mid Year Convention		$ 152,629
5	Unamortized Balance to Rate Base		$ 1,373,661

Discussion:
Adjust rate base to add regulatory asset for Electric Vehicle Program.

This adjustment is sponsored by Witness H. E. Ward.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 42
Adjust Rate Base and Reserve to Remove Non-Eligible Items

Line No.	Description	Reference Account	Total Company Amount	MD Alloc. Factor	MD Alloc. Factor %	Total MD	MD Distrib. Alloc. Factor	MD Distrib. Alloc. Factor %	Total MD Distrib
	Column (1)	(2)	(3)						
1	Non-Elig ble Amounts in 13 Mo Avg Plant in Service	101	$ 211,135						
2	Adjustment to Remove Non-Eligible Amounts	101	$ (211,135)	GP01	60.90%	$ (128,580)	S&W	89.61%	$ (115,221)
3	Non-Elig ble Amounts in 13 Mo Avg Reserve	108	$ (22,102)						
4	Adjustment to Remove Non-Eligible Amounts	108	$ 22,102	GP01	60.90%	$ 13,460	S&W	89.61%	$ 12,062

Discussion:
Adjust rate base and reserve to remove non-eligible items in 13 month average that were removed from the books in September 2022.

This adjustment is sponsored by Company Witness T. M. Ashton.

The Potomac Edison Company
Maryland Distribution
Working Papers Supporting Adjustments
12 Months Ending December 31, 2022

Adjustment No. 43
Accounting Adjustments

Line No.	Description	Reference Account	Total Company Amount	Allocation	MD Distribution Amount
	Column (1)	(2)			(3)
1	Regulatory Debits in Test Year for PE10 non-eligible costs	407.3	$ 1,048,065	Direct	$ 938,317
2	Adjustment Amount	407.3			$ (938,317)

Discussion:
Remove Regulatory Debits booked in test year for sponsorship refunds. These amounts relate to prior periods.

This adjustment is sponsored by Company Witness T. M. Ashton.

The Potomac Edison Company
Maryland Distribution Revenue Deficiency Analysis
12 Months Ending December 31, 2022

Line No.	Adjustment Number Column (1)	Description (2)	Income (3)	Rate Base (4)	Revenue Requirement (5)
1		Maryland Distribution Per Book Amounts	$ 26,321,010	$ 647,618,240	
2		per book Revenue increase @7.54%			$ 32,070,061
3					
4		Adjustments:			
5	1	Salaries and Wages-Test Year	255,884.83		264,128
6	2	Salaries and Wages-2023	321,722.96		332,087
7	3	Employee Savings Plan-Test Year	7,676.54		7,924
8	4	Employee Savings Plan-2023	9,415.48		9,719
9	5	Storm Damage	(55,153.99)		(56,931)
10	6	Remove Advertising Expense	(66,751.10)		(68,901)
11	7	Increase Postage Expense	46,132.41		47,619
12	8	Commission Assessment Increase	41,952.00		43,303
13	9	Medical Insurance Expense	58,033.79		59,903
14	10	Group Life Insurance Expense	(543.38)		(561)
15	11	Pension/OPEB Expense MTM Related	(210,314.43)		(217,090)
16	12	Pension/OPEB Expense Non-MTM Related	1,172,567.45		1,210,342
17	13	Rate Case Expense	423,557.00		437,202
18	14	O&M Expense Recovered in Covid-19 Deferral	(2,263,319.27)		(2,336,232)
19	15	Service Company Charges	(2,743,458.39)		(2,831,839)
20	16	Depreciation Expense New Rates	3,000,258		3,096,912
21	17	Depreciation Expense on Test Year Reliability Projects	596,217		615,424
22	18	Projects	594,527		613,680
23	19	Rate Case Expense Amortization	(11,152)		(11,511)
24	20	Depr Expense on Service Company Alloc of Rate Base	2,016,088		2,081,036
25	21	Conservation Voltage Reduction (407.4)	(33,050)		(34,115)
26	22	Covid-19 Regulatory Credit Removal (407.4)	2,263,319		2,336,232
27	23	Covid-19 Regulatory Asset Amortization (407.3)	1,452,046		1,498,824
28	24	Electric Vehicle Regulatory Asset Amortization (407.3)	305,258		315,092
29	25	Electric Vehicle Regulatory Credit Removal (407.4)	527,034		544,013
30	26	Payroll Taxes Salaries and Wages-Test Year	19,575		20,206
31	27	Payroll Taxes Salaries and Wages-2023	24,612		25,405
32	28	Interest Synchronization	(543,454)		773,927
33	29	State Income Taxes	(399,207)		
34	30	Federal Income Taxes	(932,331)		
35	31	Reliability Projects in Test Year		20,128,727	2,161,804
36	32 a	Reliability Projects Post Test Year		19,214,522	2,063,619
37	32 b	Reliability Projects Test Year - CWIP		7,779,093	835,466
38	33	Accum Depreciation Test Year Reliability Projects		(596,217)	(64,033)
39	34	Accum Depreciation Post Test Year Reliability Projects		(594,527)	(63,852)
40	35	Materials and Supplies		13,191,398	1,416,742
41	36	Cash Working Capital		(158,960)	(17,072)
42	37	Accumulated Deferred Income Taxes Test Year Reliability Projects		(1,737,865)	(186,645)
43	38	Accumulated Deferred Income Taxes Post Test Year Reliability Projects		(2,991,255)	(321,258)
44	39 a	Service Company Allocation of Plant in Service		25,394,387	2,727,330
45	39 b	Service Company Allocation of Reserve		(15,446,379)	(1,658,925)
46	39 c	Service Company Allocation of ADIT		(1,080,653)	(116,061)
47	40	Covid-19 Regulatory Asset		6,534,206	701,767
48	41	EV Regulatory Asset		1,373,661	147,530
49	42 a	Non-eligible amounts removed from Plant in Service		(115,221)	(12,375)
50	42 b	Non-eligible amounts removed from Reserve		12,062	1,295
51	43	Accounting Adjustments	(938,317)		(968,545)
52		Adjustment Totals		$ 70,906,978	$ 15,422,587
53					
54		TOTAL REVENUE DEFICIENCY			$ 47,492,648
55		Total Rate Base		$ 718,525,219	
56					

Line No.	Conversion to Revenue Requirement Factor Development	Rates	Factor
57	Conversion to Revenue Requirement Factor Development		
58		Rates	Factor
59	Uncollectibles	0.8437%	1.0085
60	Maryland Gross Receipt Tax	2.0000%	1.0293
61	Regulatory Assessment	0.2773%	1.0322
62	State Income Tax	8.2500%	1.1250
63	Federal Income Tax	21.0000%	1.4241

The Potomac Edison Company
Maryland Distribution Pro-Forma Adjustments
12 Months Ending December 31, 2022

Line No.	Pro-Forma Adj. No.	Description	Reference	Income
	(Column 1)	(2)	(3)	(4)
1		Going Level Rate Base	Exhibit JAS 1 Col 5, Line 35	$ 718,525,219
2		Requested Rate of Return	Exhibit JAS 1 Col 5, Line 50	7.54%
3				
4		Requested Earnings	Line 1 x Line 2	$ 54,188,230
5		Going Level Earnings	Exhibit JAS 1 Col 5, Line 18	20,838,731
6				
7		Increase in Earnings Requested	Line 4 - Line 5	$ 33,349,500
8		Revenue Conversion Factor	Col. 4, Line 45	1.4241
9				
10	44	Requested Pro-Forma Revenue Increase	Line 7 x Line 8	$ 47,492,648
11		Percent of Revenues Uncollectible	Col. 3, Line 41	0.8437%
12				
13	45	Pro-Forma Uncollectible Expense	Line 10 x Line 11	$ 400,682
14				
15		Requested Pro-Forma Revenue Increase	Line 7 x Line 8	$ 47,492,648
16		Regulatory Assessment Rate	Col. 3, Line 43	0.2773%
17				
18	46	Pro-Forma Regulatory Assessment	Line 15 x Line 16	$ 131,697
19				
20		Requested Pro-Forma Revenue Increase	Line 7 x Line 8	$ 47,492,648
21		Maryland Gross Receipt Tax	Col. 3, Line 42	2.0000%
22				
23	47	Pro-Forma Maryland Gross Receipt Tax	Line 20 x Line 21	$ 949,853
24				
25		Requested Pro-Forma Revenue Increase	Line 7 x Line 8	$ 47,492,648
26		Pro-Forma Uncollectible Expense	Line 13	(400,682)
27		Pro-Forma Regulatory Assessment	Line 18	(131,697)
28		Pro-Forma Maryland Gross Receipt Tax	Line 23	(949,853)
29		State Taxable Income	Sum Lines 25, 26, 27, 28	$ 46,010,416
30		State Income Tax Rate	Col. 3, Line 44	8.25%
31				
32	48	Pro-Forma State Income Tax	Line 29 x Line 30	$ 3,795,859
33				
34		Federal Taxable Income	Line 29 - Line 32	$ 42,214,557
35		Federal Income Tax Rate	Col. 3, Line 45	21.00%
36				
37	49	Pro-Forma Federal Income Tax	Line 34 x Line 35	$ 8,865,057
38				
39		Conversion to Revenue Requirement Factor Development		
40			Rates	Factor
41		Uncollectibles	0.8437%	1.0085
42		Maryland Gross Receipt Tax	2.0000%	1.0293
43		Regulatory Assessment	0.2773%	1.0322
44		State Income Tax	8.2500%	1.1250
45		Federal Income Tax	21.0000%	1.4241

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

HEATHER E. WARD

Concerning: Specific Ratemaking Adjustments

March 22, 2023

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Heather E. Ward, and my business address is 5001 NASA Blvd, Fairmont, West Virginia, 26554.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by FirstEnergy Service Company as an Analyst for the Rates and Regulatory Affairs Department – West Virginia/Maryland. I report to the Manager, Rates and Regulatory Affairs, and my responsibilities include the development, coordination, preparation and presentation of retail tariffs, and the development of retail electric rates, rules, and regulations. My time is devoted to tasks performed for The Potomac Edison Company ("PE or "Company") and Monongahela Power Company.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I am a graduate of West Virginia University, where I earned a Bachelor of Science in Political Science, and I am a retired Officer of the United States Air Force, having served 25 years in the Air National Guard in Charleston, West Virginia. I have over 25 years of experience with FirstEnergy Service Company or its predecessor companies, and have held positions of Representative, Customer Service; Supervisor, Customer Service; Analyst, Revenue Operations; Analyst, Customer Service Analytics; and my current position of Analyst, Rates.

Q. HAVE YOU TESTIFIED IN RATE PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes, I have testified in proceedings before the Public Service Commission of West Virginia.

II. <u>PURPOSE OF TESTIMONY</u>

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

A. The purpose of my testimony is to sponsor several of the adjustments to the 2022 test year data provided in Exhibit JAS-1 from Company witness Soltis. I will discuss the following specific adjustments:

Adjustment No. 5	Adjusts test year expenses for storm damages to a five-year average going level.
Adjustment No. 6	Removes non-eligible advertising expenses from the test year.
Adjustment No. 7	Adjusts postage expense to reflect changes in United States Postal Service ("USPS") postage rates.
Adjustment No. 8	Reflects going-level changes to the regulatory commission assessment expense.
Adjustment No. 13	Adjusts rate case expenses in the test year to recover the amounts over a three-year period.
Adjustment No. 16	Adjusts depreciation expense for new depreciation rates.

Adjustment No. 19	Reflects removal of prior rate case expense amortization.
Adjustment No. 24	Adjusts expense to add amortization of the regulatory asset for Electric Vehicles ("EV").
Adjustment No. 25	Reflects the removal of the EV deferral from the test year.
Adjustment No. 41	Reflects an increase in rate base for the EV regulatory asset.

III. RATEMAKING ADJUSTMENTS

Q. HOW HAS THE TEST YEAR DATA BEEN ADJUSTED?

A. The Company has made going-level and pro-forma adjustments to the 2022 test year to properly reflect the level of ongoing revenues and expenses of the Company for use in the establishment of future rates.

Going-level adjustments are ratemaking adjustments made to historical financial data to reflect known and measurable changes to the historical test year data. These adjustments are necessary to provide an ongoing picture of the financial status of the Company to reflect the cost of providing service after the time that new distribution rates are placed into effect. Pro-forma adjustments reflect the effect of the proposed rates on revenues and any related expense changes.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 5.

A. Adjustment No. 5 is a going-level adjustment that modifies the test year operation and maintenance ("O&M") expense level for storm damage expense. The adjustment compares the five-year annual average of storm-related expenses to the test year, with an adjustment made so that the test year expense is equal to the five-year average. The Company used a five-year average since storm expense can be a volatile category of O&M in which a particular year may not be representative of an average year. This adjustment effectively normalizes the storm expense based upon a five-year average. In conjunction with this adjustment, the Company is also proposing a new storm deferral, as explained by Company witness Valdes.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 6.

A. Adjustment No. 6 is a going-level adjustment that removes advertising expense associated with promotional, community affairs, and institutional advertising from 2022 Maryland electric distribution expenses in accordance with Code of Maryland Regulations ("COMAR") Section 20.07.04.08(F).[1] The remaining advertising expenses are informational and are eligible for recovery from customers and included in the test year consistent with COMAR Section 20.07.04.08(C).[2]

Q. PLEASE EXPLAIN ADJUSTMENT NO. 7.

A. Adjustment No. 7 is a going-level adjustment that increases the test year customer accounts postage costs to reflect the USPS postage rate increases effective in July 2022 and January 2023. This adjustment was calculated by first determining the percentage of increase over

[1] "Promotional" means advertising directed toward selling services or promoting the addition of new customers or seeking additional use of utility service. "Community affairs" means advertising directed toward influencing public opinion on a controversial issue, or the result of any legislative or administrative matter that would justify the utility civic and community position. "Institutional" means advertising directed toward establishing a favorable image of the utility company or its employees and which serves to identify the sponsor.

[2] "Informational" means advertising directed toward informing customers of charges and conditions of service, safety precautions, energy conservation, temporary or emergency conditions, employment opportunities, rate cases, annual reports, legal and financial matters.

the average cost of postage of the time period from January 2022 through June 2022, and then multiplying the postage increase percentage by the test year expense prior to the postage rate increase. The adjustment also includes the incremental increase in the number of customers enrolled in ebill in the test year. This is calculated by multiplying the incremental cumulative sum of ebill enrollments by the new postage rates. The result of this calculation is a reduction to the adjustment of the postage expense.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 8.

A. Adjustment No. 8 is a going-level adjustment that increases the test year level of regulatory commission assessment expense to annualize the increase in Maryland Public Service Commission ("Commission") assessments that was effective July 1, 2022.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 13 AND NO. 19.

A. Adjustment No. 13 reflects an increment for rate case expenses reflective of one-third of actual and projected costs of the Company's rate case. One-third of the cost is representative of one year of recovery of a requested three-year recovery amortization. These expenses include charges directly related to the rate case for items such as studies for depreciation, overall cost of capital, lead/lag, and class cost of service; legal fees; customer notifications; etc. These expenses are not normally incurred, so it is necessary for the Company to make a going-level adjustment to recover these costs over a reasonable period of time. Additionally, this adjustment includes the recovery of costs for an EV benefit cost analysis[3] and costs incurred from the Company's prior depreciation rate case.[4] The Commission has in prior rate cases allowed the recovery of these expenses to be collected over a similar time period of three years.

Adjustment No. 19 removes the 2018 rate case amortization from the test year. Recovery of the regulatory asset related to rate case expenses was granted over three years beginning March 23, 2019, in the Company's last Maryland distribution base rate case, Case No. 9490. As of March 23, 2022, recovery is complete, and no further amortization should be reflected in the test year for these expenses.

Q. PLEASE EXPLAIN ADJUSTMENT NO. 16.

A. Adjustment No. 16 increases the depreciation expense related to proposed changes in depreciation rates as filed in this case. The increase in depreciation expense was calculated by applying the current and proposed depreciation rates to the 13-month average balance of Accounts 101 and 106 for the test year. This adjustment also includes the effect of transferring the subtransmission assets from transmission Federal Energy Regulatory Commission ("FERC") accounts to distribution FERC accounts since such assets are operated as part of the distribution system, as explained by Company witness Colflesh, and are not collected as part of PE's transmission rates. The justification and support for the proposed new depreciation rates is provided in the testimony and exhibits of Company witness Spanos. Due to limitations in the Company's plant accounting system where mid-

[3] Such an analysis was required in accordance with Order No. 88997 in Case No. 9478, footnote 170.

[4] Order No. 89971 in Case No. 9490 affirmed the Proposed Order of the Public Utility Law Judge dated May 26, 2021, which, among other items, authorized the deferral of such depreciation study expenses into a regulatory asset for consideration in the Company's next base rate case (pgs. 25-26).

month depreciation rate changes cannot be accommodated, the change in depreciation rates will become effective beginning the first full calendar month following Commission order in this proceeding.[5]

Q. PLEASE EXPLAIN ADJUSTMENT NO. 24, ADJUSTMENT NO. 25, and ADJUSTMENT NO. 41.

A. In Commission Order No. 88997 in Case No. 9478, the Commission rejected the Company's proposal to recover EV Portfolio Program costs through a surcharge and instead directed PE to seek cost recovery through traditional ratemaking in a future rate case proceeding.[6] Such authorized cost recovery consisted of: (1) EV Portfolio Program O&M costs (excluding depreciation) to be deferred to a regulatory asset; (2) the regulatory asset would be amortized over a five-year period and earn a return after the balance is incorporated into rate base as part of a base rate case proceeding; and (3) capital assets would be included in rate base and depreciated over their useful lives.[7] Adjustment No. 24 adds expense to reflect recovery of the first year amortization of the regulatory asset for the Company's EV Portfolio Program costs. Adjustment No. 25 removes the regulatory credits related to the deferral of the EV Portfolio Program expenses in the test year. Adjustment No. 41 increases plant-in-service for the regulatory asset related to the EV Portfolio Program and increases accumulated depreciation for amortization of first year recovery of the regulatory asset, using a mid-year convention, with the result that the

[5] For example, if a Commission order is received on October 18, 2023, the change in depreciation rates will be effective on November 1, 2023.
[6] Order at pgs. 76-77.
[7] Proposal to Implement a Statewide Electric Vehicle Portfolio (pg. 54), filed January 22, 2018 in Case No. 9478.

unamortized balance of the regulatory asset is included in the Company's rate base.

IV. CONCLUSION

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes, it does.

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

TRACY M. ASHTON

Concerning: Pension and Other Post-Employment Benefits (OPEB); Cost Allocation and Customer Refunds

March 22, 2023

I. **INTRODUCTION**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Tracy M. Ashton, and my business address is 76 South Main Street, Akron, Ohio 44308.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Assistant Controller, Corporate of FirstEnergy Corp. ("FirstEnergy") and a number of its subsidiaries.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I have been Assistant Controller – Corporate since May 2019. From May 2008 to May 2019, I served in various positions within the finance organization including Manager of Financial Reporting and Technical Accounting and Director of Business Planning and Performance, prior to being promoted into my current role. From 2003 to 2008, I was with Deloitte & Touche, LLP where I served in various client service positions.

I received a Bachelor of Business Administration degree in Accounting from Kent State University. I am a licensed certified public accountant in Ohio.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE ANY REGULATORY COMMISSION?

A. Yes, in addition to this testimony, I have provided expert testimony before the Public Utilities Commission of Ohio and the New Jersey Board of Public Utilities.

Q. PLEASE DESCRIBE YOUR DUTIES AS ASSISTANT CONTROLLER, CORPORATE.

A. I am responsible for ensuring the accounting records of FirstEnergy and its subsidiaries are maintained in conformity with generally accepted accounting principles ("GAAP") and regulatory requirements, including the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USofA"). In addition, I am responsible for disbursements to vendors; external financial reporting; accounting research in connection with proposed business transactions; and cost analysis and accounting classification of construction projects.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is two-fold. The first section explains and supports the level of pension and other post-employment benefits ("OPEB") expense that The Potomac Edison Company ("PE" or Company") is requesting for recovery in this base rate case filed with the Maryland Public Service Commission ("Commission"), including the impact of certain accounting adjustments and to propose a mechanism to normalize pension and OPEB expense. The second section of my testimony explains the services provided and costs charged to PE in the test year by the FirstEnergy Service Company ("FESC") under the FESC Service Agreement, as well as the refund of other costs previously charged to PE.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The first part of my testimony discusses the following adjustments to pension and OPEB expense: (1) remove the pension and OPEB mark-to-market ("MTM") amount from the 2022 test year recognized by PE under GAAP and FERC USoA; and (2) include, for ratemaking purposes, the recalculated amount of the requested pension and OPEB expense by amortizing the net accumulated actuarial loss over future periods, consistent with the Delayed Recognition Methodology (also referred to as the "Smoothing Mechanism"), as applied for ratemaking purposes in the 2018 distribution base rate case and approved by the Commission in Order No. 89072 in Case No. 9490. However, as discussed herein, PE is also requesting that test year non-MTM pension and OPEB expense be adjusted to reflect the most recent five-year average to mitigate (or smooth) a portion of the volatility in the expenses for purposes of setting PE's distribution base rates.

To support the proposed level of pension and OPEB expense to be recovered in base rates, my testimony will provide background on the accounting for pension and OPEB costs under GAAP, including the two accounting methods prescribed by GAAP for the accounting of actuarial gains and losses – one of the components of pension and OPEB costs. I also will provide support for the adjustments necessary to determine the appropriate level of test year pension and OPEB expense for PE.

Lastly, with respect to pension and OPEB expense, year-to-year fluctuations in annual earnings, and in some years losses, on the pension and OPEB assets are becoming more material with respect to the Company's income statement and financial performance. These year-to-year market fluctuations also can materially impact test year pension and OPEB expense and customer rates. Therefore, PE is seeking to implement a mechanism to defer the annual difference between the annual pension and OPEB expense calculated using the delayed recognition method for ratemaking purposes, and the approved pension and OPEB expense for rate treatment in future base rate cases.

The second part of my testimony discusses the services provided and costs charged to PE under the FESC Service Agreement. I will discuss the process for charging the FESC costs for those services to PE and its affiliates within the FirstEnergy system. In this regard, I will also review the manner by which FESC fairly and equitably charges the costs for its services directly and/or indirectly to PE, FirstEnergy, and its affiliates that receive such services, including the cost allocation methodologies for charging indirect costs. I will also describe a change in FirstEnergy's method to capitalize costs allocated to its subsidiaries by FESC, including the impact to historical costs. In addition, I explain how certain transactions that were improperly classified, misallocated, or lacked proper supporting documentation regarding certain vendors, were corrected as well as summarize the proactive review performed by FirstEnergy of certain non-operating or non-recoverable costs. I will also describe the controls in place to ensure proper allocation of costs to PE by FESC, including the reinforcement of direct charging policies, training employees on time charging, enhanced procedures on invoice processing, and review of detailed items billed to PE by FESC.

II. <u>PENSION ACCOUNTING AND RATEMAKING BACKGROUND</u>

Q. HOW ARE PENSION AND OPEB COSTS DERIVED UNDER GAAP?

A. Pension and OPEB costs or credits generally consist of five components:

1. Service cost – Represents the actuarial present value of benefits attributed by the pension and OPEB plans' benefit formula to services performed by employees during the reporting period.

2. Interest cost – Annual interest on the present value of the benefit obligations (liability) at the beginning of the year.
3. Estimated return on plan assets – Represents the estimated return on plan investments by applying the expected long-term rate of return to beginning-of-year plan asset balances.
4. Prior service cost amortization – Represents amortization, over the average remaining service period of employees, of changes to the benefit obligations due to plan amendments.
5. Actuarial gains and losses – Represents the net gain or loss resulting from a change in the value of plan assets and benefit obligations due to experience which differs from assumptions used to estimate the value of end-of-year plan asset and benefit obligation balances. Such differences can be related to the return on plan assets, changes in the discount rate used to calculate the present value of benefit obligations, and other actuarial assumptions such as mortality rates. As further described below, companies either recognize actuarial gains and losses immediately in earnings ("mark-to-market accounting") or through delayed recognition whereby actuarial gains and losses are recorded in accumulated other comprehensive income ("AOCI"), a component of equity, and amortized into earnings over a future period.

As noted in the description of cost component 5 above, companies have the option to recognize the earnings effect of actuarial gains and losses immediately or through delayed recognition. For companies that apply immediate recognition (mark-to-market accounting), the full amount of actuarial gains and losses are recognized in earnings immediately. For companies that apply delayed recognition, actuarial gains and losses are captured in AOCI and amortized over a future period. Therefore, the difference in the two "options" is simply a matter of timing with respect to earnings recognition, with the delayed recognition method producing a less volatile level of gains or losses.

Q. WHAT ARE ACTUARIAL GAINS AND LOSSES UNDER GAAP?

A. As noted in cost component 5 above, actuarial gains and losses represent the net gain or loss resulting from a change in the value of plan assets and benefit obligations due to experience which differs from assumptions used to estimate the end-of-year plan asset and benefit obligation balances.

In the case of plan assets, the difference between the actual return on plan investments during the year compared to the estimated return on plan investments (cost component 3, above) represents an actuarial gain (if the actual return is higher than the estimated return) or actuarial loss (if the actual return is lower than the estimated return). This component simply adjusts the expected return on plan assets in a given year to the actual return on plan assets in that year.

In the case of benefit obligations, a change in the assumed discount rate that measures the benefit obligation at the beginning of the year to the end of the year will result in an actuarial gain (if the actual discount rate is higher at the end of the year than the assumed discount rate at the beginning of the year) or an actuarial loss (if the actual discount rate at the end of the year is lower than the assumed discount rate at the beginning of the year). The present value of benefit obligations may also be affected by changes in assumed future payouts due to mortality experience that differ from assumed mortality rates, changes in assumed wage increases (in the case of pension costs), changes in assumed health care inflation rates (in the case of OPEB benefits) and other actuarial assumptions. If the present value of benefit obligations increases due to changes in actuarial assumptions, an actuarial loss will be incurred; conversely, if the present value of benefit obligations decreases due to actuarial assumption changes, an actuarial gain will be recognized. Actuarial gains or losses on plan assets are netted against actuarial gains or losses on benefit obligations to determine the net actuarial gain or loss for the plans for a given year.

Q. PLEASE EXPLAIN PE'S BOOK ACCOUNTING FOR PENSION AND OPEB EXPENSE.

A. PE's test year pension and OPEB expense is calculated in accordance with GAAP. In December of each year, or whenever a plan is determined to qualify for remeasurement, FirstEnergy and its subsidiaries (including PE) record actuarial gains or losses on their pension and OPEB plans to earnings through a MTM adjustment (immediate recognition).

Q. WHEN ARE PENSION/OPEB COSTS SET FOR THE YEAR?

A. FirstEnergy (including PE) recognizes actuarial gains and losses for its pension and OPEB plans in December of each year, or whenever a plan is determined to qualify for remeasurement. The remaining components of pension and OPEB costs, including service costs, interest cost on obligations, expected return on plan assets, and amortization of prior service costs, are set at the beginning of each calendar year and recorded on a monthly basis. Changes in asset performance and discount rates will not impact these costs during the year, however, future years could be impacted by changes in the market. Pension and

OPEB expense calculated at the beginning of the year is the monthly cost, net of amounts capitalized.

ADJUSTMENTS TO PENSION AND OPEB EXPENSE

Q. WHAT ADJUSTMENTS HAVE BEEN MADE TO PENSION AND OPEB EXPENSE?

A. Effective December 31, 2011, FirstEnergy and its subsidiaries (including PE) adopted MTM accounting (immediate recognition) for their pension and OPEB plans ("Accounting Change"), which is a preferable method of accounting under GAAP. As a result of the Accounting Change, PE records a MTM adjustment for actuarial gains or losses immediately to earnings in December of each year, or whenever a plan is determined to qualify for a remeasurement.

However, for ratemaking purposes in this distribution base rate filing, PE has removed the effect of this MTM adjustment from GAAP pension and OPEB expense and replaced it with actuarial gains or losses calculated under the delayed recognition (or "smoothed") methodology. This calculation is consistent with the manner in which PE calculated pension/OPEB costs in its last distribution base rate case, which was approved by the Commission in Order No. 89072 in Case No. 9490.

Q. HOW WERE THE ADJUSTMENTS AND TEST YEAR PENSION AND OPEB EXPENSE CALCULATED?

A. There are several steps to the calculation. First, the fiscal year 2022 net actuarial loss recorded by PE is subtracted from the per-books level of expense. Then, under my direction, the Company's actuary calculated the amount of amortization of the accumulated net actuarial loss that would have been included in pension and OPEB expense under the delayed recognition methodology. An adjustment was then made representing the amount of amortization of the accumulated net actuarial loss calculated under the delayed recognition methodology. This adjustment is listed as Adjustment No. 11 and provided in Exhibit JAS-2 to the direct testimony of Company witness Soltis.

Additionally, the Company has included an adjustment that averages the non-MTM pension and OPEB expenses for the past five years ending December 31, 2022. Similar to the MTM adjustment, this adjustment for non-MTM pension and OPEB expense effectively smooths the costs over a historical period to determine an average level to include for ratemaking purposes. This adjustment is listed as Adjustment No. 12 and provided in Exhibit JAS-2 to the direct testimony of Company witness Soltis.

NORMALIZATION OF PENSION AND OPEB EXPENSE

Q. WHY IS PE SEEKING APPROVAL OF A MECHANISM TO NORMALIZE PENSION/OPEB EXPENSE ("PON MECHANISM")

A. FirstEnergy has a qualified pension plan with a total qualified Projected Benefit Obligation for both active employees and retirees of approximately $8.4 billion and qualified pension assets totaling $6.7 billion, as of year-end 2022. Over the past 10 years, FirstEnergy has contributed $3.4 billion to this qualified pension plan, achieving a funded ratio of approximately 79% for FirstEnergy's qualified pension plan as of December 31, 2022.

PE's portion of the qualified pension plan's Projected Benefit Obligation for both active employees and retirees is approximately $190 million and PE's portion of the qualified pension assets is $218 million, as of year-end 2022. Over the past 10 years, PE has contributed $73 million to the qualified pension plan, achieving a funding ratio of approximately 115%. PE also maintains an OPEB plan with a Projected Benefit Obligation for both active employees and retirees of approximately $13 million and assets totaling $29 million, as of year-end 2022. The funded ratio was 220% at the end of 2022.

The Company asserts that these benefit plans are an important part of the total compensation package which attracts and retains a skilled workforce. However, the annual fluctuations in investment performance can become significant in the context of PE's income statement and overall financial performance. Therefore, the Company is seeking to moderate the impacts to its income statement from the impacts of the investment performance of pension/OPEB assets due to market fluctuations, which are outside of the Company's control. The PON Mechanism also may moderate the impacts on customers' rates from market fluctuations as well.

Q. HOW DOES THE PON MECHANISM WORK?

A. As previously explained, PE will calculate pension and OPEB expense under the Delayed Recognition (or Smoothing) Methodology. The pension/OPEB expense ultimately approved by the Commission in this proceeding sets the expense included in distribution base rates ("Approved Pension/OPEB Expense"). For each calendar year following the conclusion of the base rate case (i.e., on or after the rate effective date), PE will calculate the annual pension/OPEB expense ("Annual Expense") under the Delayed Recognition

Methodology and compare that expense to the Approved Pension/OPEB Expense from its most recent base rate case. To the extent that the Annual Expense is less than the Approved Pension/OPEB Expense, customers will be provided the benefit of the reduction in the Annual Expense and the Company will defer a regulatory liability for 100% of the difference between Annual Expense and Approved Pension/OPEB Expense. To the extent that the Annual Expense is greater than the Approved Pension/OPEB Expense, the Company will defer a regulatory asset for 90% of the difference between the Annual Expense and the Approved Pension/OPEB Expense. Therefore, when the Annual Expense is greater than the Approved Pension/OPEB Expense, customers will also benefit from a 10% reduction in the amount deferred. The net amounts deferred for each calendar year will accumulate until the next base rate case, where the Company will request and the Commission will decide on an appropriate amortization and recovery or refund period for the regulatory asset or liability.

Q. WILL THE RECOVERY/REFUND OF AMOUNTS RELATED TO THE PON MECHANISM DEFERRAL BE IN ADDITION TO APPROVED PENSION/OPEB EXPENSE?

A. Yes. The Company would recover its pension/OPEB expense and, in addition, seek to refund, or recover, the PON Mechanism deferral balance at its next base rate case. The Company would provide a credit to customers, in the instance where the deferred amount is a regulatory liability, or collect from customers, in the instance where the deferred amount is a regulatory asset, the amortization of the PON Mechanism deferral through future base rates.

Q. HOW DOES THE PROPOSED PON MECHANISM BENEFIT CUSTOMERS?

A. Fluctuations in pension and OPEB costs are expected to normalize or offset over the long-term. However, in the short-term, market trends or corrections result in pension and OPEB costs that may not be representative of the actual long-term cost of providing these benefits to active employees and retirees. Often after a correction in the markets, for example the events that occurred in 2022, there is some near-term rebound. As this rebound occurs, pension and OPEB expense will decrease as market performance of the pension and OPEB assets improves. Using this scenario as an example, should pension and OPEB expense be set for ratemaking purposes at the time of one of these market correction events, the cost that customers would be paying for pension and OPEB expense would not reflect the near-term recovery in the markets and, for this period, would be greater than the amount that would need to be recovered to compensate the Company for its pension and OPEB expense. Again, because of the size of the pension and OPEB assets, these amounts year-to-year can be material. The PON Mechanism would accumulate the changes in Annual Expense as compared to the Approved Pension/OPEB Expense and ensure that customers were credited for any reductions in pension and OPEB expense as compared to Approved Pension/OPEB Expense and only paid 90% of any increases in pension and OPEB expense as compared to Approved Pension/OPEB Expense – the result being that customers pay less than the Company's cost to provide these benefits to its employees.

Q. HOW DOES THE PROPOSED PON MECHANISM BENEFIT THE COMPANY?

A. Under the PON Mechanism, PE would defer credits or expenses in a regulatory asset on its books, based on the difference between Approved Pension/OPEB Expense and the

Annual Expense in each calendar year following the conclusion of the base rate case and the effective date of base rates implemented as a result of same. In years where the market performance of the pension and OPEB assets was less than expected, the deferral of 90% of the increase in pension and OPEB expense (as compared to the Approved Pension/OPEB Expense) would reduce the volatility on PE's income statement and financial performance.

Q. DOESN'T THE DELAYED RECOGNITION METHODOLOGY ALREADY PROVIDE FOR SMOOTHING OF IMPACTS RELATED TO PENSION/OPEB ASSET INVESTMENT PERFORMANCE?

A. For customers, yes. Customers benefit from the smoothing aspects of the Delayed Recognition Methodology. However, because pension and OPEB expense is reset only during a base rate case proceeding, it does not capture fluctuations in pension and OPEB expense between base rate cases, which have become more significant with the growth in pension and OPEB assets over time. PE contends that fluctuations in investment performance are significant enough between base rate cases to warrant deferral treatment to mitigate the impacts to PE's income statement and financial performance, and to further mitigate volatility in customers' rates.

Q. WHY SHOULD THE COMMISSION APPROVE THE PON MECHANISM AT THIS TIME?

A. This is somewhat of an emerging issue for utilities with large pension and OPEB assets and obligations. Because the Projected Benefit Obligation continues to grow as utilities continue to offer these benefits to its active employees and retirees, the corresponding assets must also continue to increase to satisfy these benefit obligations. As a result, the year-to-year fluctuations in annual earnings, and losses in some years, on the pension and OPEB assets as well as the impact of interest costs and volatility in the discount rate utilized to measure benefit plan obligations, are all becoming more material with respect to the Company's income statement and financial performance. Further, the year-to-year market fluctuations also can materially impact test year pension and OPEB expense and, therefore, customer rates. Because of these increasing impacts, PE requests that the Commission consider a deferral mechanism, such as the proposed PON Mechanism, that provides some offset for the utility to downside market performance of the pension and OPEB assets in years when it occurs and also ensures that customers pay no more than the cost of these benefits, which in the case of the proposed PON Mechanism, will result in costs to customers that are less than the cost of these benefits.

III. FESC RELATIONSHIPS, CHARGES AND ALLOCATIONS

BACKGROUND

Q. PLEASE DESCRIBE FIRSTENERGY AND ITS CONSOLIDATED SUBSIDIARIES.

A. FirstEnergy is a regulated utility that, through its subsidiary companies, primarily owns and operates regulated businesses that are involved in the generation, transmission, and distribution of electricity.

FirstEnergy's regulated business is comprised of ten regulated electric companies that serve customers in Maryland, West Virginia, New Jersey, Ohio, Pennsylvania, and New York. FirstEnergy's wholly-owned regulated electric companies (The Potomac

Edison Company, Monongahela Power Company, Jersey Central Power & Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, The Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, and West Penn Power Company) serve approximately six million customers in the Midwest and Mid-Atlantic regions, covering 65,000 square miles across six states. FirstEnergy also has majority ownership in three regulated independent transmission businesses, which have approximately 24,000 miles of high-voltage lines and two regional transmission operation centers within the PJM Interconnection, LLC ("PJM") region. PJM is the regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.[1]

Q. IN ADDITION TO ITS REGULATED BUSINESS, DOES FIRSTENERGY ALSO HAVE UNREGULATED BUSINESSES?

A. FirstEnergy has limited unregulated business. After completion of the FirstEnergy Solutions and subsidiaries ("FES"), and FirstEnergy Nuclear Operating Company ("FENOC") bankruptcy (filed March 31, 2018, with emergence February 27, 2020) and the transfer of the competitive Pleasants Power Station in 2020, FirstEnergy completed its exit from non-regulated generation production. Upon the completion of FES's and FENOC's emergence from bankruptcy as a fully separate non-affiliated entity (Energy

[1] It should be noted that not all of the FirstEnergy transmission assets are part of the three independent transmission businesses. Some of FirstEnergy's utilities, including PE, currently own their own transmission assets for which they are provided with transmission support services through FESC, and the costs for such transmission support services are addressed in proceedings related to transmission rates before the FERC and not as part of this proceeding. However, I should also clarify that the same personnel who provide the transmission support services, which are not addressed in this proceeding, also provide some distribution support services, which are addressed in this proceeding.

Harbor), the unregulated business now comprises less than 1% of FirstEnergy's gross plant assets.

Q. PLEASE DESCRIBE THE ROLE OF FESC WITHIN FIRSTENERGY.

A. FESC is a centralized service provider formed for the purpose of providing administrative, management, operations support, and other services to FirstEnergy and its affiliated companies. It has been long understood[2] that providing the broad array of services described herein throughout a holding company system such as the FirstEnergy System, by and through a centralized mutual service company, such as FESC, is more efficient and less costly than providing, managing, and staffing such services at each individual associate company.

The FirstEnergy System is also able to take advantage of its economies of scale to more efficiently utilize its resources by providing such services from centralized groups within FESC. For instance, among other things, FESC has a greater degree of bargaining power with suppliers than would FirstEnergy and each of its associate companies negotiating individually, because FESC negotiates, where appropriate, on behalf of the overall FirstEnergy System.

Q. PLEASE BE MORE SPECIFIC ABOUT THE TYPES OF SERVICES CENTRALLY PROVIDED BY FESC TO FIRSTENERGY AND ITS ASSOCIATE COMPANIES.

[2] For instance, the predecessor to PUHCA 2005, the Public Utility Holding Company Act of 1935 ("the '35Act"), and the regulations (e.g., Rules 87, 88, 90, 91 and 93) promulgated thereunder, permitted, and regulated, the use of, and charging of costs by, mutual service companies that provided services within registered public utility holding company systems.

A. FESC provides various corporate, managerial, and administrative support services to FirstEnergy and its associate companies, including PE, in the following areas: executive management, accounting and tax, investor relations, corporate responsibility and communications, treasury, risk, rates and regulatory affairs, strategy, planning and business performance, supply chain, human resources and corporate services, legal, ethics and compliance, internal auditing, corporate affairs and community involvement, compliance and regulated services, external affairs, information technology and corporate security, transmission, utility operations, safety and human performance, operations, utility services, construction and design services, transformation, competitive products and services, customer engagement, customer care and customer policy and solutions.[3]

A full list and description of the services provided by FESC are set forth in Exhibit A to the Service Agreement (as defined below) that is attached hereto as Exhibit TMA-1 to my testimony.

Q. DOES FESC PERFORM UTILITY OPERATIONS SERVICES FOR PE OR ANY OTHER OF THE FIRSTENERGY UTILITY COMPANIES?

A. Although FESC provides utility operations-related ***support*** services, it is important to emphasize that FESC, generally, does not perform the "operations" services, which are, instead, performed by the FirstEnergy utility companies themselves, including PE. One exception to this, however, is in vegetation management, which is centrally managed at FESC for all the entities, such as PE, which engage in such work.

[3] Please note that FESC also provides, on a limited basis, goods in connection with such services. However, for the sake of simplicity and clarity, I only refer to "services" in my testimony.

<u>FESC COST ACCOUNTING</u>

Q. ARE YOU FAMILIAR WITH FESC'S BOOKS AND RECORDS AND HOW THEY ARE MAINTAINED?

A. Yes, I am. The books and records of FESC are maintained in accordance with the FERC USofA and GAAP.

Q. CAN YOU PLEASE PROVIDE AN OVERVIEW OF HOW FESC ACCOUNTS, AND CHARGES, FOR THE COSTS OF ITS SERVICES?

A. Yes. FESC renders services to FirstEnergy and its associate companies at cost. The full costs of the services provided by FESC are either directly or indirectly charged to FirstEnergy and its associate companies (including PE). Some FESC costs are directly charged to a particular company, such as PE, because those costs are related to services performed solely for PE. An example of such a direct charge is the charge for economic development, where a group of FESC employees based in Maryland provide economic development services exclusively for PE. Each of those employees effectively directly charges his or her time and expenses to PE.

Other FESC costs are indirectly charged when the costs are not directly chargeable to a single associate company because the services benefit multiple associate companies, and the particular costs of the service is not identified to any individual associate company or companies. One example of such indirectly charged costs is an employee's work associated with the execution of the monthly financial close in the FirstEnergy SAP Enterprise Resource Planning system ("SAP"), which is FirstEnergy's comprehensive system-wide management software system. Such an employee's time would be indirectly charged to FirstEnergy and its associate companies using cost allocation methodologies that I discuss herein.

As I will further explain, the processes for accounting for, and charging, FESC costs, including the cost allocation methodologies for charging indirect charges, are integrated into SAP.

Q. PLEASE FURTHER CLARIFY WHAT YOU MEAN BY "DIRECTLY CHARGED."

A. When I say that a cost is "directly charged," I am using that terminology to convey that the time and expenses associated with the service are charged directly to the identifiable associate company for which the service is being rendered. The costs of services are charged directly to the associate company receiving the services or for a particular transaction.

Q. PLEASE FURTHER CLARIFY WHAT YOU MEAN BY "INDIRECTLY CHARGED."

A. When I say that a cost is "indirectly charged," I am using that terminology to convey that the charges are not specifically directly charged to a single associate company. In such cases, one could also say that such cost is "allocated" or "charged on an allocated basis." While these terms can be used interchangeably, I have attempted to be consistent in using the term "indirectly charged" to simplify the distinction between such charges and those that are directly charged. For instance, it is sometimes said that one cost is "directly charged" while another cost is "indirectly allocated." This combination of terms may create confusion that I am hoping and attempting to avoid.

Q. ARE THE TERMS "DIRECTLY CHARGED" AND "INDIRECTLY CHARGED" THE SAME AS "DIRECT COSTS" AND "INDIRECT COSTS"?

A. No. The former terms are methods of charging. The latter terms are types of costs. Since I have explained the former terms, I will also explain the latter terms.

Direct costs are costs that can be specifically identified with a particular service performed for an associate company. Costs incidental or related to direct items are also classified as direct costs. Direct costs may be directly charged if reasonably identifiable to a particular recipient associate company. For example, FirstEnergy Corp.'s Board of Director fees are directly charged to FirstEnergy Corp., with no other affiliate bearing the expense.

Indirect costs are costs of a general overhead nature such as support costs that cannot be identified with a particular service. This includes but is not limited to overhead costs (i.e., payroll, stores handling, construction), administrative and general expenses, and various payroll taxes. Costs incidental or related to indirect items are also classified as indirect costs. Indirect costs may be directly charged if reasonably identifiable to a particular recipient associate company; otherwise, indirect costs are indirectly charged using an approved cost allocation methodology.

Q. WHAT ARE THE COMPONENTS OF THE SERVICE COSTS THAT ARE CHARGED BY FESC, WHETHER CHARGED DIRECTLY OR INDIRECTLY?

A. Service costs are fully loaded, meaning that they include the direct costs incurred to provide a service plus the indirect costs (such as appropriate overheads) incidental or related to a service whether charged directly or indirectly.

Q. WHEN A SERVICE IS PROVIDED TO A GROUP OF COMPANIES, DOES FESC DIRECTLY OR INDIRECTLY CHARGE THE COSTS FOR SUCH A SERVICE?

A. It depends. If the costs can be reasonably identified and related to the particular transaction for the particular individual associate companies, then the costs are directly charged to each individual associate company in the group. If they cannot, then the costs must be indirectly charged using an appropriate cost allocation methodology. However, I wish to emphasize that whenever practicable (to the extent excessive effort or expense is not required), costs that can be identified as related to a particular service provided to a particular associate company are directly charged to that associate company. But, to repeat, where the costs cannot be so identified, they are indirectly charged using an approved cost allocation methodology.

Q. WHAT DO YOU MEAN BY "COST ALLOCATION METHODOLOGY?"

A. A "cost allocation methodology" is a method or process for distributing costs for services rendered that are not directly charged to a single associate company, such as charges to multiple associate companies, which are indirectly charged.

Q. WHERE ARE THE FESC COST ALLOCATION METHODOLOGIES FOUND?

A. The cost allocation methodologies used by FESC today are set forth in the FESC (Service Agreement) and are the same ones that were approved by the U.S. Securities and Exchange Commission ("SEC") in 2003. The cost allocation methodologies are also listed in the FERC Form 60, which FESC uses to report to the FERC annually.

A copy of the FERC Form 60 for 2022 encompassing the test year in this case is being finalized for filing with FERC and will be filed as a supplement to this case as soon as it is filed. As I discuss further below, the FirstEnergy cost allocation methodologies and the procedures for using them are maintained and reviewed annually by the FirstEnergy General Accounting department, which is within the FirstEnergy Controllers Department and reports to me.

Q. HOW DOES FESC USE COST ALLOCATION METHODOLOGIES?

A. FESC has no earnings, renders services at cost to FirstEnergy and its associate companies and, therefore, all its costs must be fairly and equitably distributed to FirstEnergy and its associated companies. The cost allocation methodologies are used to accurately distribute those costs that are not directly charged to a particular associate company, and, therefore, are indirectly charged to, and among, the FirstEnergy associate companies in compliance with the standards promulgated by FERC under PUHCA 2005 (including cost allocation methodologies previously approved by the SEC under the '35 Act and applicable state requirements). The particular cost allocation methodology used with respect to any particular service varies based on the service provided and the associate company or companies receiving the service.

Q. HOW MANY COST ALLOCATION METHODOLOGIES DOES FESC USE?

A. As described in the Service Agreement, FESC has eighteen cost allocation methodologies available, of which eleven are currently in use, to appropriately and accurately distribute the costs of services, which are to be indirectly charged to and among FirstEnergy and its associate companies.

Q. DOES THE IDENTITY OF THE RECIPIENT ASSOCIATE COMPANY PLAY A ROLE IN DETERMINING THE USE OF A COST ALLOCATION METHODOLOGY?

A. Yes. For example, if a service is being provided only to an unregulated segment of FirstEnergy's business, then the costs that need to be indirectly charged in a general manner would be indirectly charged using the "Multiple Factor-Non-Utility" cost allocation methodology so that such costs are not borne by any of the FirstEnergy utilities in the regulated segment.

Q. ARE THE COST ALLOCATION METHODOLOGIES GROUPED TOGETHER IN ANY WAY THAT IS HELPFUL TO UNDERSTANDING HOW THEY WORK?

A. Yes. Seven of the cost allocation methodologies pertain to information technology services. Four are used as general cost allocation methodologies with respect to costs that are not readily identifiable with particular cost drivers (i.e., a measurable event or quantity that can influence the level of costs incurred for or by a particular activity and which can be directly traced to the origin of the costs themselves). The remaining seven cost allocation methodologies are identifiable to particular cost drivers, an example of which would be employee headcount for employee benefit costs.

Q. HOW ARE THE COST ALLOCATION METHODOLOGIES RELATED TO THE SERVICES PROVIDED BY FESC?

A. The Service Agreement lists the service categories and particular types of services along with a general description of the services and a reference to the cost allocation methodology (or methodologies) that is/are most likely to be used for costs associated with such services that are to be indirectly charged. As discussed later in my testimony, the costs are accumulated and allocated at the cost center level, which is the lowest level of cost collector in SAP. These cost centers and the associated allocation method are reviewed annually.

Q. ARE THE COST ALLOCATION METHODOLOGIES CHANGED REGULARLY OR PERIODICALLY?

A. No, they have been approved by the SEC and, with respect to PE, accurately reflect the most relevant cost drivers of the organization.

Q. DOES ANY ASPECT OF THE COST ALLOCATION PROCESS CHANGE FROM TIME TO TIME?

A. While the cost allocation methodologies themselves have not changed, the data inputs required to apply the cost allocation methodologies are updated on an annual basis based on actual experience. For example, the general cost allocation methodology "Multiple Factor–Utility" requires an averaging of three factors related to a FirstEnergy utility's percentage share of all the FirstEnergy utilities' plant, operations, and maintenance ("O&M") expenses, and revenues. This data will vary from year to year based upon actual results of operations. As a result, while the methodologies would not change, the percentage share for an associate company and the percentage allocation among associate companies within the methodology can change from year to year based on actual results.

Q. EARLIER YOU REFERRED TO SAP. PLEASE EXPLAIN HOW FIRSTENERGY USES SAP.

A. SAP is the FirstEnergy resource planning software system that links and coordinates business processes to perform core business functions such as, for example, maintaining a general ledger, financial reporting, inventory management and purchasing transactions, in a fully integrated enterprise management system. SAP has been maintained through regular functional enhancements (multiple releases per year) to support business operations, as well as implementing major version updates that introduce new business functionality, the most recent of which was completed in 2015.

SAP is used to manage work, share information, track customer accounts, and meet other business needs. SAP contains the functions and processes for capturing, reporting, and directly charging and indirectly charging FESC costs to and among FirstEnergy and its associate companies. SAP is currently organized to maintain, among other things, (i) separation of costs between FirstEnergy's regulated and non-regulated associate companies, and (ii) an adequate audit trail on the books and records of FirstEnergy and its associate companies.

Q. PLEASE DISCUSS THE ROLE OF COST COLLECTORS.

A. Attributing and charging costs accurately to FirstEnergy and its associate companies requires the costs to be captured in SAP. This is the job of cost collectors, which are accounting devices used to plan, track, and account for costs of different categories or types of work. Cost collectors include orders, work breakdown structures ("WBS") and cost centers. Only one of these three types of cost collectors can be entered on a document during data entry. Orders (i.e., sales, production, process, purchase, internal or work order that uniquely identifies a cost source) and WBSs (i.e., a cost collector that organizes in a hierarchy the actions and activities to be carried out in a project) are temporary cost collectors because the costs accumulated using these cost collectors ultimately settle to a cost center or balance sheet account. A cost center is the principal and lowest level of cost collector, where the costs of providing services are accumulated to be either directly charged or indirectly charged.

Q. PLEASE DESCRIBE THE USE OF COST CENTERS.

A. Cost centers are the principal type of cost collector in SAP. Within SAP, cost centers are assigned to departments and/or managers responsible for certain areas of the business such as functional areas within, for example, human resources, finance, facilities, information systems, administrative support, and legal. Each employee within the FirstEnergy System, including at FESC, is assigned to a cost center that relates to the area of the business or category of service for which they are responsible (e.g., human resources, legal, treasury). The cost center provides the mechanism for collecting the costs associated with those employees and the services they provide, including overheads, incidental and related costs. All employees are required to ensure that their time in providing services is captured (i.e., by recording the time spent on various tasks on a timesheet). In the case of FESC, this also means identifying the appropriate cost center for the associate company, or companies, receiving such services. Ultimately, both the service provider cost center and the service recipient cost center track charges and payments for the costs associated with the services rendered.

Q. ARE THE DESCRIPTIONS AND USES OF COST CENTERS REVIEWED PERIODICALLY?

A. Yes. As part of FirstEnergy's annual Sarbanes-Oxley ("SOX") internal control reviews, General Accounting performs an annual review of the allocation methodologies used for indirect charges to determine whether: 1) billing allocators are still valid; 2) new allocation factors are needed; and 3) cost centers are using the correct allocation factors. Additional details about this annual review of cost centers are provided in the "Controls" section of my testimony below.

Q. IS EMPLOYEE TIME CHARGING SUBJECT TO REVIEW?

A. Yes. Supervisory review of employee time charged out of their home cost center is regularly performed to ensure time charged is appropriate and the cost center (or other cost collector) being used is proper. This includes review of the time document charges in relationship to employees' work schedules. In addition, training is provided to all business units to reinforce appropriate time charging.

Q. BESIDES TIME CHARGES, ARE THERE OTHER SOURCES OF COSTS CAPTURED IN SAP?

A. Other-than-labor costs are accounted for in SAP based on expense reports, vendor invoices, journal entries, and system interfaces (such as depreciation, taxes). The costs associated with these sources would also flow to appropriate cost centers for tracking, billing, and collection.

Q. HOW ARE COSTS TRANSFERRED IN SAP FROM FESC TO PE?

A. In responding to this question, it may be helpful to recall my earlier discussion of FESC costs that are directly or indirectly charged. FESC costs are accumulated in the cost centers and other relevant cost collectors and are either (i) "directly charged", for those costs originating within FESC that relate to services identified as benefiting only PE (for instance), or (ii) "indirectly charged" using appropriate general and/or specific cost allocation methodologies associated with the services rendered, where the costs are identified as benefiting PE and one or more of FirstEnergy and its other associated companies.

Q. PLEASE EXPLAIN HOW THE FESC O&M INDIRECT COSTS HAVE CHANGED SINCE THE COMPANY'S LAST BASE RATE CASE.

A. Costs indirectly billed by FESC have increased since the Company's last distribution base rate case in part due to expansion in departments to support FirstEnergy's mission and strategy, including but not limited to, creating a new Office of Ethics and Compliance to oversee organization-wide compliance, assurance, training and communications, creation of an Innovation Center and Digital Factory, and build out of our customer support organization to enhance the customer experience, expand communication channels and improve customer satisfaction, as well as creation of a new Organizational Performance Management and Strategy department. As part of an effort to gain efficiencies across the FirstEnergy operating companies, certain services were centralized from the operating companies to FESC increasing the indirect costs. Examples of these services include, among others, vegetation management, engineering, work management and safety services. General wage and benefit costs for FESC employees have also increased since the last rate case consistent with competitive market rates and rise in healthcare costs. Higher spend on public safety programs, software fees associated with critical systems, and corporate insurance coverage are also contributing to the rise in costs indirectly billed by FESC.

Q. DID ANY ACCOUNTING METHODS OR POLICY CHANGES IDENTIFIED THROUGH THE FERC AUDIT IMPACT THE FESC AMOUNTS IN THE TEST YEAR?

A. Yes. The FERC Division of Audits and Accounting ("DAA") within the Office of Enforcement of the FERC completed an audit of FirstEnergy for the period January 2015 to September 2021. DAA found that, according to their audit report, FirstEnergy's utilities capitalized Administrative and General ("A&G") overhead costs to Account 107, Construction Work in Process ("CWIP"), using a capitalization method that was not definitely related to construction activities based on timecard reports or a representative time study. To remedy this finding, DAA recommended that FirstEnergy retain an independent, third-party entity to conduct a representative labor time study for the allocation of A&G overhead costs incurred to CWIP. As a result of the labor time study, which was completed during 2022, FirstEnergy adjusted its capitalization rate for its A&G overhead costs. While the change in capitalization rate had no impact on the amount of FESC indirect costs allocated to PE, it did result in higher indirect costs recorded to O&M than capital in the test year.

Q. WHEN DID PE MAKE THE CHANGE TO ITS A&G CAPITALIZATION METHODOLOGY?

A. The independent, third-party entity completed the time study for FirstEnergy during 2022, and the revised capitalization methodology for A&G was applied effective January 1, 2022.

The overall weighted average capitalization rate resulting from the new methodology was approximately 28% in 2022 as compared to approximately 57% in the last base rate case.

Q. DID THE ADJUSTMENT OF THE A&G CAPITALIZATION RATE HAVE ANY IMPACT ON HISTORICAL COSTS?

A. The FERC audit report recommended that FirstEnergy estimate the costs that would have been allocated to CWIP from the audit period, 2015 through 2021, using the newly calculated rates resulting from the time study, and remove those costs from CWIP for FERC reporting purposes. The results of the time study indicated that over the period, on average, FESC employee activities would support a capitalization rate of approximately 26% as compared to a historical rate of approximately 57%. FirstEnergy calculated the difference between historical capitalized overhead costs and those calculated as a result of the time study, including adjusting for a corresponding impact to accumulated depreciation and Allowance for Funds Used During Construction, to determine the estimated net book value of the adjustment. As a result of this analysis, PE reclassified approximately $19 million of costs from capital accounts to a regulatory asset as of December 31, 2022, for FERC reporting purposes. Of the costs being moved into the regulatory asset, those on PE's books prior to the end of the test year from PE's last rate case (June 30, 2018) would have already been subject to a prudency review by the Commission. Discussions with FERC audit staff remain ongoing, and as such, these estimates are subject to change.

VI. CONTROLS

Q. ARE THE COMPANY'S BOOKS AND RECORDS AUDITED BY AN INDEPENDENT ACCOUNTING FIRM?

A. Yes. PricewaterhouseCoopers, LLP ("PwC") audited the Company's 2021 financial statements and PE's FERC Form No. 1, as to which PwC concluded that FirstEnergy's and PE's financial statements present fairly, in all material respects, the financial position in conformity with GAAP and in accordance with accounting requirements of the FERC's USofA, respectively. PwC also audited FirstEnergy's and PE's financial statements for 2022.

Q. PLEASE ADDRESS THE CONTROLS THAT ARE IN PLACE WITH RESPECT TO CHARGES AND EXPENSES THAT FESC EITHER DIRECTLY CHARGES OR INDIRECTLY CHARGES TO PE.

A. The FirstEnergy General Accounting function within the FirstEnergy Controller's department, which reports to me, is responsible for maintaining the cost allocation methodologies, which includes, among other things:

1. Annually reviewing cost allocation methodologies utilized with each service provided to determine if the most appropriate allocation methodology is being utilized and that the appropriate associate companies are being billed for services performed. This includes reviewing the application of the factors within the SAP ERP System. New allocation methods, if any, are identified, but cannot be used until approved, as necessary, by certain regulatory authorities. The results of this annual review are discussed with and reviewed by PwC and FirstEnergy's Internal Audit department as part of annual internal controls testing.
2. Testing and validating that overhead and allocation results are reasonable. During the monthly closing process, the overhead activity is reviewed to determine that the results are appropriate and complete.

3. Monitoring and maintaining existing overheads and allocations to ensure sender (source) amounts are being applied or allocated appropriately.
4. Monitoring and analyzing the application of overheads to direct costs.

In addition, PE utilizes other control mechanisms that monitor the services being provided by FESC. These control mechanisms include billing and review procedures to ensure the accuracy of FESC billings and internal/external audit examinations.

Q. PLEASE DESCRIBE THE BILLING PROCESS AS A CONTROL MECHANISM.

A. The FESC charges to PE are generated within SAP on the basis of the recorded activity to cost centers, work orders and time records. The billing process is a monthly automated settlement of these charges within SAP. As mentioned earlier, the time documents are subject to review and approval by the supervisor or manager responsible for the employees completing such time records. In addition, FESC billings to PE are reviewed and compared to budget monthly by the FirstEnergy Utilities ("FEU") Business Services group. If required, detailed FESC information (i.e., time sheets, invoices) is available to the FEU Business Services group for further analyses.

Q. PLEASE DESCRIBE THE BILLING RECONCILIATION PROCEDURES AS A CONTROL MECHANISM.

A. Another control that is performed monthly is the reconciliation of FESC billings to FESC expenses with regard to services rendered to the FEU group of utilities, including PE. Such reconciliation ensures that all expenses have been appropriately allocated and detects any over- or under-billings for any cost center.

Q. PLEASE DESCRIBE THE AUDIT PROCESS AS A CONTROL OVER THE FESC CHARGES TO PE.

A. The internal auditing department periodically reviews and audits the FESC charges to assess the design and operating effectiveness of the control environment for FESC charges that are processed through SAP. In general, the main objectives of the internal audit review are to determine whether internal controls over the billing process to the associated companies, including PE, are adequate and effective, as well as to review the cost allocation methodologies in effect and the application of these methodologies. This would include a review to ensure compliance with applicable regulatory requirements, as well as with FESC policies and procedures pertaining to billing. The specific audit procedures to be utilized will typically include interviews, observations, tests, and other procedures deemed necessary to accomplish the audit objectives.

Q. CAN YOU ELABORATE FURTHER REGARDING THE USE OF THE AUDIT PROCESS AS A CONTROL?

A. Yes. Since 2005, the Internal Auditing department has conducted SOx control tests annually to ensure the appropriate use of cost allocations within SAP and that the SAP system is distributing costs correctly and in accordance with the SOx controls set in place to assure compliance with regulatory requirements.

Q. CAN YOU DISCUSS THE USE OF THIS CONTROL RELATIVE TO PE?

A. Yes. The Internal Auditing department completed an audit of PE's internal controls related to FirstEnergy's Cost Allocation Manual ("CAM") in 2022. The audit determined the internal controls that support and govern the cost allocation process are adequately designed to provide a reasonable level of assurance regarding reliability and integrity of the allocation of the charges billed to PE, in accordance with the Service Agreement and CAM requirements. PE's external auditor PwC also examined management's assertion regarding costs allocated to PE during 2021, which was filed with the Commission on July 8, 2022 and is included as Exhibit TMA-2.

Furthermore, the Company underwent an audit by the FERC Division of Audits for the period January 1, 2015 through September 30, 2021, with a subsequent report issued in 2022, which included selective tests of the FESC cost allocation methodologies and charges billed by FESC to the FEU utilities, including PE. The audit did not identify exceptions with respect to the cost allocation methodologies, but provided recommendations related to the capitalization method of FESC costs, as described above, as well as recommended FirstEnergy perform an analysis of certain non-recoverable costs to ensure appropriate accounting classification, as described further below.

Finally, in connection with the issuance of PE's financial statements, audit opinions are issued annually by an independent public accounting firm for the Company's GAAP financial statements and FERC Form 1.

FirstEnergy is currently completing a comprehensive effort under which it has updated the Shared Service Agreement and in the process of updating the CAM to ensure they both properly reflect current business activity.

Q. HAS THE COMPANY PROVIDED A COPY OF ITS CAM?

A. Yes. Pursuant to Section 4-208(b)(1) of the Public Utility Companies Article, on July 8, 2022 the Company filed: (1) the 2021 CAM; (2) a Certificate of Training Program relating to the CAM; (3) an Affidavit Relating to Cost Allocation and Asset Transfer Pricing Principles; (4) lists of parent, service company, and utility officers for the period covered by the CAM; and (5) the independent audit opinion with respect to the CAM prepared by PricewaterhouseCoopers LLP. The July 8, 2022 filing is included as Exhibit TMA-2.

Q. HAS THE COMPANY IDENTIFIED ANY ISSUES OUTSIDE OF THE ALLOCATION PROCESS WITH RESPECT TO CHARGES FROM FESC TO PE?

A. Yes, it has. I will address this in three parts. First, it is my understanding that the Commission is already aware, through Case No. 9667, that following the investigation of Ohio HB 6 activities, FirstEnergy's Board of Directors discovered and reported that certain costs may have lacked proper documentation or may have been improperly classified or misallocated to FirstEnergy's distribution utilities, including to PE. Company witness Valdes discusses in his testimony how PE proposes to fully refund, with interest, all such amounts that have been included in PE's rates. Mr. Valdes' testimony reflects that the amount associated with this first category was just under $38,000, which he then adjusts for multiple rates years and then applies carrying costs to.

Second, in addition to, and separate from, those amounts, and as a result of recommendations for improvement identified during the FERC audit, as well as part of a proactive corporate effort, FirstEnergy reviewed certain non-operating or non-recoverable costs and identified costs that were recorded to utility operating accounts that were included in electric service rates. Those costs reviewed included costs associated with advertising, sponsorships, competitive services, and lobbying. The review covered the period of the FERC Audit, 2015-2021, except for review of sport sponsorships, which extended back to 2013. Mr. Valdes' testimony reflects that the amount associated with this category was approximately $196,000, which again he adjusts for multiple rates years and then applies carrying costs to.

Lastly, FirstEnergy also retained Craig Energy & Financial Services ("CEFS") to review and confirm the results of the company's internal review, described above, as well as to recommend and then review other potential areas of non-recoverable expenses. Through its review, CEFS identified certain additional items, which Mr. Valdes' testimony reflects that the amount associated with this category was approximately $68,000, which again he adjusts for multiple rates years and then applies carrying costs to. CEFS issued its final report to FirstEnergy in the first quarter of 2023.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE COSTS EXAMINED BY CEFS AND THE COSTS WHICH WERE IMPROPERLY CLASSIFIED, MISALLOCATED, OR LACKED PROPER SUPPORTING DOCUMENTATION TO PE AS DISCUSSED IN CASE NO. 9667?

A. The charges that were identified as improperly classified, misallocated, or lacked proper supporting documentation discussed in my first point above and in Case No. 9667 are separate and unrelated to the proactive review FirstEnergy performed of certain non-operating or non-recoverable costs, as described in my second point above, which was also examined by CEFS, as detailed in my third point above. FirstEnergy conducted comprehensive reviews of past charges discussed above and identified additional charges that needed to be refunded to customers. FirstEnergy then worked with the state rate directors, as discussed in the testimony of Company witness Valdes, to determine what portion of the charges were recovered through customer rates, and how customers could be made 100% whole for any such rate impacts. Company witness Valdes explains in detail how this correction process worked with respect to Maryland. Company witness Valdes also provides the calculation of the make-whole payment to customers.

Q. ARE THERE ANY ADJUSTMENTS TO THE TEST YEAR TO REFLECT THE PREVIOUSLY MENTIONED CORRECTIONS?

A. Yes, in addition to the make-whole payment to customers discussed by Company witness Valdes, there are two related adjustments to the Company's 2022 test year in this base rate case. Adjustment No. 42 is an adjustment to remove certain non-operating and non-recoverable costs amounts described above from the Company's rate base. Specifically, in September 2022, an accounting entry was made to adjust plant and accumulated reserve to remove the previously identified charges. This adjustment effectively removes such charges from rate base. Adjustment No. 43 is an adjustment to the 2022 test year to remove the regulatory debit recorded when establishing the regulatory liability that will ultimately flow back to customers as a refund, since this amount related to prior years and would not be included in future customer rates. Adjustment Nos. 42 and 43 are provided in Exhibit JAS-2 to the direct testimony of Company witness Soltis.

Q. WHAT STEPS HAS FIRSTENERGY TAKEN TO ADDRESS THE ISSUES THAT LED TO THESE CHARGES BEING ASSESSED TO PE?

A. As noted, FirstEnergy hired CEFS to do a separate review to confirm management's analysis of non-recoverable and non-operating expenses. In its review, CEFS stated that it "believes in all material respects, the major, potentially high-risk, assessment coverage areas were identified and evaluated for compliance with the USofA, associated ratemaking impacts, and potential refunds owed to the regulated transmission and distribution affiliates' customers." All refunds identified have been recognized on the books of PE. The recommendations identified by CEFS are currently being implemented and anticipated to be completed by the end of 2023.

Additionally, FirstEnergy has developed a new monthly report that provides additional details, including vendor names, source of the cost and FERC account charged, for items that are billed to the utility operating companies, including PE, from FESC. This report has aided accounting, business services, rates, and internal auditing in their review of FESC charges billed to the operating companies, including those in these identified categories of non-recoverable or non-operating expenses, to ensure appropriate accounting and ratemaking treatment.

FirstEnergy also implemented various procedures for non-purchase order ("non-PO") transactions, such as energy purchases, legal penalties, and income tax payments that, by their nature, do not have a corresponding purchase order. SAP has been configured to require a user who enters a non-PO invoice for payment to actively affirm the transaction is governed by a valid contract or FirstEnergy has a legal obligation to make payment, the payment amount entered in SAP agrees with the supporting vendor invoice, and the payment is for verified services rendered and/or goods received. SAP requires invoices to be assigned to approvers with the property level of signature of authority as defined within FirstEnergy's Delegation of Authority Practice. This Practice also sets forth the authority level for employes to enter into commitments on behalf of the Company. In addition, Accounts Payable performs a quarterly review of all vendor payments without an associated purchase order to ensure the payment was processed in accordance with accounting policies.

Throughout 2022, FESC employees were provided training around direct charging, time charging, and invoice processing to mitigate the risk of inclusion of non-recoverable or non-operating charges in customer rates.

Q. CAN YOU PLEASE DESCRIBE THIS REFERENCED TRAINING IN SOME MORE DETAIL?

A. The training was facilitated by FirstEnergy's Corporate Business Services to over 4,000 FESC employees and reinforced the existing "Time Charging for Service Company Employee Activity" policy. The training covered the importance of charging time to appropriate entities, projects or initiatives as well as included an explanation of new lobbying cost centers created to track and record time spent on lobbying activities. The training also served to remind FESC employees of appropriate invoice processing procedures, including an explanation of types of costs that should be considered non-recoverable and the corresponding accounting to apply.

All employees who entered or approved invoices in SAP were also required to complete a web-based training during 2021. This training included a review of policies for both payments made under existing purchase orders as well as non-purchase order payments and expectations of preparers and reviewers to, among other things, validate the appropriate cost collectors are charged. These additional procedures have been implemented in order for FirstEnergy to ensure proper accounting and ratemaking treatment.

Q. DO YOU HAVE ANY CONCLUSIONS ABOUT THE DEGREE AND EXTENT OF THE CONTROLS IN PLACE?

A. In my view, as Assistant Controller, Corporate, the company has ample control over the FESC costs. First, PE reviews monthly the amounts FESC bills to it. Second, the cost collector system, billing review and reconciliation procedures, as well as the periodic audits performed by the internal audit function and external auditors, provide more than adequate opportunities for effective communications, decisions or other actions pertaining to quantity and coordination of service issues between PE and FESC. Third, executive and director level oversight is provided by senior management and the Boards of Directors for disclosure and accountability per the Sarbanes-Oxley Act. Fourth, as set forth above, PE and FirstEnergy have implemented various steps to increase the controls pertaining to the identification of non-recoverable or non-operating expenses and have proposed a reasonable approach to addressing the issues previously identified. All provide a comprehensive framework for assuring the fairness and reasonableness of the charges for the services provided to PE by FESC.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY IN REGARD TO PENSION AND OPEB EXPENSES.

A. PE's proposed adjustments to test year pension and OPEB expense are appropriate to: (1) eliminate the volatility on PE's rates of the MTM accounting for pension and OPEB costs used for financial reporting purposes; and (2) appropriately reflect pension and OPEB costs for ratemaking purposes by amortizing net actuarial losses over future periods. In addition, PE's adjustments related to non-MTM pension and OPEB costs smooth out the changes that have historically happened from year to year. Finally, the proposed PON Mechanism will benefit both customers and the Company by reducing the impact of volatility in future pension and OPEB expenses.

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY IN REGARD TO FESC RELATIONSHIPS, CHARGES AND ALLOCATIONS.

A. FESC provides necessary services to PE pursuant to approved cost allocation methodologies and direct charges. The level of costs charged to PE in the test year is appropriate and reasonable. FirstEnergy and PE have extensive controls in place by which FESC charges and allocations are reviewed on an ongoing basis.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

SERVICE AGREEMENT

This Service Agreement ("Agreement") is entered into as of the ___ day of ______, 20__, by and between each of the associate companies listed on the signature page hereto (each a "Client Company" and collectively the "Client Companies"), and FirstEnergy Service Company ("Service Company"), an Ohio corporation.

WHEREAS, Service Company is a direct wholly-owned subsidiary of FirstEnergy Corp. ("FirstEnergy");

WHEREAS, Service Company provides corporate, administrative, management and other services to FirstEnergy and the Client Companies; and

WHEREAS, Client Company desires to purchase such corporate, administrative, management and other services from Service Company as Client Company may request or require in accordance with this Agreement and as required by the laws, rules, regulations, judgement, and orders of any federal or state regulatory body whose approval and regulation is, pursuant to the laws of said jurisdiction, necessary and a legal prerequisite to Client Company's operations to accomplish Client Company's business purpose (collectively, "Law");

NOW, THEREFORE, in consideration of the mutual covenants contained herein and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby agree as follows:

1. <u>DESCRIPTION AND PROVISION OF SERVICES</u>.

(a) Service Company shall perform such corporate, administrative, management and other services for Client Company (the "Basic Operating Services"), including but not limited to, executive services, accounting and finance, internal auditing, risk management, human resources, corporate affairs, corporate communications, information technology, policy and compliance, records management, and legal services. Service Company shall provide such Basic Operating Services to Client Company until this Agreement terminates.

(b) In addition to Basic Operating Services, Service Company shall provide to Client Company such services as Client Company deems necessary to achieve Client Company's business purpose or as required by Law (the "Additional Services", and together with Basic Operating Services, the "Services"). Additional Services include but are not limited to, operations management, construction, maintenance, asset oversight, customer service, rates and regulatory affairs, environmental, corporate real estate, strategic planning and operations, flight operations, performance management, business development, and investment management. Service Company shall provide such Additional Services until such time as Client Company indicates otherwise by written notice.

(c) Exhibit A hereto lists and describes all Services that are available from Service Company, as will be reviewed annually and updated as required by Law or when otherwise deemed appropriate by the parties hereto.

2. PERSONNEL.

Service Company will employ such executive officers, accountants, financial advisers, technical advisers, attorneys and other persons with the qualifications to provide the Services, as appropriate and necessary. Service Company may, at its discretion, also arrange for the services of nonaffiliated experts, consultants, and attorneys in connection with the performance of any of the Services provided under this Agreement.

3. COMPENSATION AND ALLOCATION.

(A) COMPENSATION.

As and to the extent permitted by Law,

(i) any Services provided by Service Company pursuant to this Agreement shall be at cost;

(ii) the costs for Services rendered by Service Company shall cover direct and indirect costs, plus any reasonable expenses and fees incurred by Service Company to provide such Services to Client Company (collectively, "Costs"); and

(iii) Client Company shall pay such Costs as appropriate.

(B) COST ALLOCATION METHODOLOGY.

The Costs of Services provided by Service Company pursuant to this Agreement shall be directly assigned, distributed, or allocated by activity, project, program, work order or other appropriate means, as follows:

(i) a direct charge, whereby Costs are assigned to the Client Company directly benefiting from the Service provided; and/or

(ii) an indirect charge, whereby the appropriate share of the Costs of Services provided by Service Company that are not directly charged to a Client Company will be allocated among Client Companies by utilizing the method that most accurately distributes such Costs. Applicable cost allocation factors, which are included in FirstEnergy's cost allocation manual, will be reviewed annually and updated as required by Law or when otherwise deemed appropriate by the parties hereto.

4. BILLING AND PAYMENT.

Billing and payment for Services provided by Service Company shall be by making appropriate accounting entries on the books of Client Company and Service Company. Monthly reports provided to Client Company will include details of Costs associated with Services provided by Service Company. Financial settlement for Services provided by Service Company will be made on a monthly basis, with billing to occur as soon as practicable after the close of the month, and financial settlement or accounting entries completed within thirty (30) days of billing. Any amount remaining unpaid by Client Company after thirty (30) days following billing shall bear interest thereon from the due date of billing until financial settlement at a rate equal to the prime rate on the due date.

5. APPLICATION OF LAW.

This Agreement shall be subject to the approval of any state electric utility regulatory commission whose approval is, by the laws of the federal government or said state, a legal prerequisite to the execution and delivery or the performance of this Agreement.

6. TERM AND TERMINATION.

(A) INITIAL TERM.

This Agreement shall commence as of the date first indicated above and shall continue thereafter for a period of five (5) years (the "Initial Term"), unless sooner terminated pursuant to this Section 6.

(B) RENEWAL TERM.

Upon expiration of the Initial Term, this Agreement shall automatically renew for successive five (5)-year terms unless either party provides written notice of nonrenewal no later than three hundred and sixty-five (365) days prior to the end of the then-current term (each a "Renewal Term" and together with the Initial Term, the "Term"). If the Term is renewed for one or more Renewal Term, the terms and conditions of this Agreement during each Renewal Term shall be the same as the terms and conditions in effect immediately prior to such renewal. If either party provides timely notice of nonrenewal, this Agreement shall terminate on the expiration of the then-current Term, unless sooner terminated in this Section 6.

(C) VOLUNTARY TERMINATION.

Any party to this Agreement may terminate this Agreement by providing one hundred eighty (180) days written notice of such termination to the other party.

(D) TERMINATION IN COMPLIANCE WITH LAW.

This Agreement is subject to termination or modification at any time to the extent its performance may conflict with any rule, regulation, requirement, or order of the state or federal electric utility regulatory commission with jurisdiction over the Client Company.

(E) AUTOMATIC TERMINATION.

This Agreement shall automatically terminate upon Client Company (i) ceasing to be an affiliate of Service Company; (ii) becoming insolvent or admitting its inability to pay its debt obligations as they come due; (iii) becoming subject, voluntarily or involuntarily, to any proceeding under any bankruptcy or insolvency law, which is not stayed within ten (10) business days or is not dismissed or vacated within thirty (30) business days after filing; (iv) being dissolved or liquidated or taking any corporate action for such purpose; (v) making a general assignment for the benefit of creditors; or (vi) having a receiver, trustee, custodian, or similar agent appointed by order of any court of competent jurisdiction to take charge of or sell any material portion of its property or business. In the event of a termination of this Agreement pursuant to this Section 6(E), there shall be a transition period not to exceed ninety (90) days for which the Service Company will continue to provide Services at cost to Client Company.

7. GENERAL.

(A) ENTIRE AGREEMENT.

This Agreement, together with its exhibits, constitutes the entire understanding and agreement of the parties with respect to its subject matter, and effective upon the execution of this Agreement by the respective parties hereof, any and all prior agreements, understandings or representations with respect to this subject matter are hereby terminated and canceled in their entirety and are of no further force and effect, except to the extent transactions thereunder have taken place prior to such effective date, in which case such agreements will govern the terms of such transactions.

(B) ASSIGNMENT AND BINDING EFFECT.

No assignment of this Agreement or a party's rights, interests or obligations hereunder may be made without the other party's written consent, which shall not be unreasonably withheld, delayed, or conditioned. This Agreement shall inure to the benefit of and shall be binding upon the parties and their respective successors and assigns.

(C) NOTICE.

Where written notice is required by this Agreement, all notices, consents, certificates, or other communications hereunder shall be in writing and shall be deemed given to the persons and at the addresses identified below (or to such other person and address as a party may give in a notice given in accordance with the provisions hereof) only as follows: (i) if given by personal delivery, upon such personal delivery, (ii) if sent for next day delivery by United States registered, certified or express mail, or overnight delivery service, on the date of delivery as confirmed by written confirmation of delivery, or (iii) if sent by electronic mail, upon electronic confirmation of receipt, except that if such confirmation occurs on a day that is not a business day, then such notice or other communication will not be deemed effective or given until the next succeeding business day. Notices sent in any other manner will not be effective.

To Client Company:	c/o President 76 South Main St. Akron, OH 44308 [President Email]
To Service Company:	c/o Vice President and Controller 76 South Main St. Akron, OH 44308 [Controller Email]

(D) EXTENSION OF TIME; WAIVER.

A party may (i) extend the time for the performance of any of the obligations of the other party under this Agreement, and/or (ii) waive compliance with any of the agreements or conditions for the other party's benefit contained herein. Any such extension or waiver will be valid only if set forth in a writing signed by the acting party. No waiver by a party of any default, misrepresentation, or breach hereunder, whether intentional or not, may be deemed to extend to any prior or subsequent default, misrepresentation, or breach hereunder or affect in any way any rights arising because of any prior or subsequent occurrence. No failure or delay of a party to exercise any right or remedy under this Agreement will operate as a waiver thereof, and no single or partial exercise of any right or remedy will preclude any other or further exercise of the same, or of any other, right or remedy.

(E) GOVERNING LAW.

This Agreement shall be governed by and construed in accordance with the laws of the State of Ohio, without regard to its conflict of law provisions.

(F) HEADINGS.

The headings contained in this Agreement are inserted for convenience only and will not affect in any way the meaning or interpretation of this Agreement.

(G) SEVERABILITY.

The provisions of this Agreement will be deemed severable, and the invalidity or unenforceability of any provision will not affect the validity or enforceability of the other provisions hereof.

(H) MODIFICATION.

This Agreement may not be amended or modified except by a writing signed by each of Service Company and Client Company.

(I) COUNTERPARTS.

This Agreement may be executed in two or more counterparts, each of which will be deemed an original but all of which together will constitute one and the same instrument. This

Agreement will become effective when one or more counterparts have been signed by each party and delivered to the other party, it being understood that the parties need not sign the same counterpart. The exchange of copies of this Agreement and of executed signature pages by electronic mail in "portable document format" (".pdf") or by a combination of such means, will constitute effective execution and delivery of this Agreement as to the parties and may be used in lieu of an original Agreement for all purposes. Signatures of the parties transmitted by electronic mail or by .pdf shall be deemed to be original signatures for all purposes.

(J) THIRD PARTY BENEFICIARIES.

Nothing in this Agreement shall be deemed to create any right in any creditor or other person or entity not a party hereto. This Agreement shall not be construed in any respect to be a contract in whole or in part for the benefit of any third party.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed effective as of date first above written.

FirstEnergy Service Company

By: ___________________________________
Name:
Title: Vice President and Controller

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed effective as of date first above written.

[Client Company][, on its own behalf and on behalf of its subsidiaries [•]]

By: ______________________________________
Name:
Title: [Officer]

EXHIBIT A

DESCRIPTION OF SERVICES

Service	Description
Executive Management	Provide strategic, financial, and operational leadership for all aspects of the business.
Accounting and Tax Support	Various accounting and tax services, including but not limited to: financial reporting; utility reporting and billing; property, general, regulatory, and tax accounting; accounts payable; accounting research; utility and transmission business services; finance transformation; tax planning; federal, state, and local tax and rates; and return on Service Company assets.
Investor Relations, Corporate Responsibility and Communications Support	Various services, including but not limited to: investor relations; corporate responsibility and rating agencies; internal, external, and customer communications; and graphic and document production.
Treasury Support	Various treasury services, including but not limited to: pension and investment management; business development; and capital markets, cash, and e-commerce.
Risk Support	Various risk-related services, including but not limited to: insurance and credit risk; enterprise risk management and risk control; and operational risk management.
Rates and Regulatory Affairs Support	Various regulatory services, including but not limited to: load forecasting and rate initiatives; distribution and transmission rates; and state and federal regulatory affairs.
Strategy, Planning & Business Performance Support	Various services, including but not limited to: business planning and performance; and long-term planning.
Supply Chain Support	Various supply chain services, including but not limited to: supply chain solutions/standards; material operations; and strategic category management.
Human Resources & Corporate Services Support	Various services, including but not limited to: talent management; total rewards; pension and other post-employment benefits; labor/employee relations and corporate safety; diversity, equity, and inclusion; and HR technology.

Service	Description
Corporate Services	Various services, including but not limited to: administrative services; real estate; and flight operations.
Legal Support	Various services, including but not limited to: legal services; records and information compliance; claims; and corporate secretary.
Ethics & Compliance Support	Perform investigations and risk assessments on compliance matters; provide policy management and compliance training and communication.
Internal Auditing Support	Provide risk-based independent assurance and consulting internal audit services; evaluate risk management, control, and governance processes, and administer the program for management's testing of internal controls.
Corporate Affairs and Community Involvement Support	Coordinate community partnerships and employee volunteer opportunities; administer contributions for charitable, social and community welfare programs.
Compliance & Regulated Services Support	Various regulatory compliance services, including but not limited to: regulated commodity sourcing; FERC and RTO technical support; NERC compliance; FERC and state compliance reporting; regulated settlements.
External Affairs Support	Various external affairs services; including but not limited to: regional external affairs; state and federal government affairs; and legislative and regulatory policy and administration.
Information Technology & Corporate Security	Various IT and security services, including but not limited to: IT innovation and enablement; cyber security and transmission security operations center; compliance field support and physical security; and physical security compliance and technology.
Transmission Support	Various transmission-related services, including but not limited to: operations; planning and protection; substation services; and assets and records control.
Utility Operations	Various utility-related services, including but not limited to: state executive management; engineering services; distribution engineering and customer accounts support; work management operations; and operational strategy and alignment.

Service	Description
Safety & Human Performance	Various services, including but not limited to: human performance and governance; safety data analytics, training and work practices, and operations.
Operations Support	Various services, including but not limited to: regional workforce development; metering and support systems; central electric lab and BETA lab support; work management and process improvement; distribution system operations; vegetation management; emergency preparedness; and ADMS/GIS Project.
Utility Services	Various services, including but not limited to: environmental support; generation services; and fuels and generation commercial operations.
Construction & Design Services	Various services, including but not limited to: transmission and substation design; transmission project management; portfolio management; and transmission program support.
Transformation Support	Various services, including but not limited to: emerging technology programs and strategy; and transformation office and program.
Competitive Products & Services	Various services, including but not limited to: FirstEnergy sales; and consumer products and marketing.
Customer Engagement	Various customer-related services, including but not limited to: national accounts and customer support; economic development; energy efficiency implementation, compliance and reporting; and customer analytics and reporting.
Customer Care	Various customer services, including but not limited to: customer contact centers, management, and care support; and revenue operations.
Customer Policy & Solutions	Various customer-related services, including but not limited to: FEP operations; and customer policy, advocacy, and solutions.

PotomacEdison
A FirstEnergy Company

10802 Bower Avenue
Williamsport, MD 21795

Jeffrey P. Trout

Telephone: 301.790.6116
Fax: 330.436.8124
jtrout2@firstenergycorp.com

July 8, 2022

VIA EFILE

Andrew S. Johnston, Executive Secretary
Maryland Public Service Commission
6 St. Paul Street
Baltimore, MD 21202

Re: CAM Audit

Dear Secretary Johnston:

Pursuant to Section 4-208(b)(1) of the Public Utility Companies Article and to the Commission's currently-operative filing procedures, enclosed please find the independent audit opinion with respect to The Potomac Edison Company's Cost Allocation Manual prepared by Pricewaterhouse Coopers LLP (Attachment 1). Also enclosed is the "Management's Statement Regarding Costs Allocated to The Potomac Edison Company during 2021" (Attachment 2) and accompanying Schedule of Allocated Costs (Attachment 3) which are referenced in the audit opinion.

As you are aware, under COMAR 20.40.02.07 and .08 as amended, utilities are only required to file their CAM and related documents when they file a rate case. Thus Potomac Edison is not required to file its 2021 CAM. However, in anticipation of Staff requests for further information with respect to the CAM audit, enclosed please also find:

(1) FirstEnergy Service Corporation's Cost Allocation Manual ("CAM") used by Potomac Edison (Attachment 4), which was the subject of the audit;
(2) a Certificate of Training Program relating to that CAM (Attachment 5);
(3) an Affidavit Relating to Cost Allocation and Asset Transfer Pricing Principles regarding that CAM (also in Attachment 5); and
(4) lists of parent, service company, and utility officers for the period covered by that CAM (Attachment 6).

Please also note that Potomac Edison has already filed, in its annual ring-fencing report, an organization chart for the same period – see ML#240499.

If you have any questions about this matter, please do not hesitate to contact me.

Very truly yours,

Jeffrey P. Trout
Senior Corporate Counsel

JPT/kbw

cc: David Valcarenghi, PSC Staff

pwc

Report of Independent Accountants

To Management and the Board of Directors of
The Potomac Edison Company

We have examined management's assertion of The Potomac Edison Company defined within the schedule titled, 'Management's Statement Regarding Costs Allocated to The Potomac Edison Company during 2021' (the "Schedule"), which is as follows: (i) FirstEnergy has complied with the policies and procedures of the FirstEnergy Service Company ("FESC") Cost Allocation Manual ("CAM") in all material respects, (ii) costs have been allocated to The Potomac Edison Company ("Potomac Edison") in accordance with the criteria set forth in FESC's CAM pursuant to the Code of Maryland Regulations Section 20.40.02.07 (CAM Requirements), and (iii) costs and transactions were appropriately charged to Potomac Edison in accordance with the criteria set forth in the CAM for the twelve-month period ended December 31, 2021. The Potomac Edison Company's management is responsible for its assertion. Our responsibility is to express an opinion on management's assertion based on our examination.

Our examination was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the examination to obtain reasonable assurance about whether management's assertion is fairly stated, in all material respects. An examination involves performing procedures to obtain evidence about management's assertion. The nature, timing and extent of the procedures selected depend on our judgment, including an assessment of the risks of material misstatement of management's assertion, whether due to fraud or error. We believe that the evidence we obtained is sufficient and appropriate to provide a reasonable basis for our opinion.

We are required to be independent and to meet our other ethical responsibilities in accordance with relevant ethical requirements related to the engagement.

Our procedures did not include the independent verification of the completeness of costs subject to allocation to Potomac Edison; therefore, we express no opinion regarding this attribute.

In our opinion, management's assertion defined within the Schedule, which is as follows: (i) FirstEnergy has complied with the policies and procedures of the FirstEnergy Service Company ("FESC") Cost Allocation Manual ("CAM") in all material respects, (ii) costs have been allocated to The Potomac Edison Company ("Potomac Edison") in accordance with the criteria set forth in FESC's CAM pursuant to the Code of Maryland Regulations Section 20.40.02.07 (CAM Requirements), and (iii) costs and transactions were appropriately charged to Potomac Edison in accordance with the criteria set forth in the CAM for the twelve-month period ended December 31, 2021, is fairly stated, in all material respects.

This report is intended solely for the information and use of Management and the Board of Directors of The Potomac Edison Company, Management and the Board of Directors of FirstEnergy Corp. and the Maryland Public Service Commission, and is not intended to be and should not be used by anyone other than the specified parties.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
June 29, 2022

Management's Statement Regarding Costs Allocated to The Potomac Edison Company during 2021

Management Assertion

Management of FirstEnergy Corp. ("FirstEnergy") is responsible for the accompanying schedule, "FirstEnergy - Costs Allocated to The Potomac Edison Company in 2021 by Allocation Factor and Expense Category" (the "Schedule") and for complying with the requirements of the Annotated Code of Maryland, Public Utility Companies Article §4-208(b).

Management asserts the following:

(i) FirstEnergy has complied with the policies and procedures of the FirstEnergy Service Company ("FESC") Cost Allocation Manual ("CAM") in all material respects.

(ii) Costs have been allocated to The Potomac Edison Company ("Potomac Edison") in accordance with the criteria set forth in FESC's CAM pursuant to the Code of Maryland Regulations Section 20.40.02.07 (CAM Requirements).

(iii) Costs and transactions were appropriately charged to Potomac Edison in accordance with the criteria set forth in the CAM.

The criteria for allocating and charging costs are reflected in the cost assignment process, as set forth in the CAM, which is summarized as follows:

- Labor-related services performed by FESC on behalf of an affiliate are directly charged at a standard activity rate per unit of labor, which includes direct costs and related overheads.
- Costs accumulated by FESC that are not directly charged are allocated based on specified allocation ratios as set forth in the CAM.
- Costs that are incurred by a legal entity other than FESC on behalf of an affiliate are directly charged or allocated based on specified allocation ratios to the applicable affiliate.
- Direct charges have been excluded from the attached schedule.

There are no adjustments required to the policies and procedures set forth in the CAM based on prior Commission rulings.

As stated in Section V - FirstEnergy Service Company Allocation Codes – Allocation Percentages, the percentages shown in the CAM are the base percentages including all applicable companies in the calculation. FirstEnergy employs a methodology that permits inclusion or exclusion of companies within each methodology, depending upon the cost being allocated, so percentages within each method may vary by company depending on need. The table below shows the various percentages that were used in 2021 as subsets of the base allocation factors for Potomac Edison.

	Potomac Edison %
Multiple Factor Utility	
Multiple Factor Utility – Base (see CAM)	5.32%
Multiple Factor Utility – Excluding MP Gen	5.46%
Multiple Factor Utility – Excluding MP Gen and TrAIL Co	5.65%
Multiple Factor Utility – Excluding transmission	6.43%

Multiple Factor Utility – Excluding transmission and MP Gen	6.63%
Multiple Factor Utility - Excluding Ohio and All Mon Power	8.38%
Multiple Factor Utility – Jersey,Transmission, All Mon Power,Potomac Edison&West Penn	9.78%
Multiple Factor Utility – Jersey,Transmission,Mon Power,Potomac Edison&West Penn	10.25%
Multiple Factor Utility – Jersey, Met Ed, Potomac Edison, West Penn, TrAIL, MAIT	12.25%
Multiple Factor Utility – PA Utilities, Mon Power & Potomac Edison	14.79%
Multiple Factor Utility – GPU & Potomac Edison	14.81%
Multiple Factor Utility – Jersey, All Mon Power, Potomac Edison & TrAIL	16.50%
Multiple Factor Utility – Penelec, Mon Power, Potomac Edison, West Penn & MAIT	17.43%
Multiple Factor Utility – Penelec, Met Ed, Potomac Edison & West Penn	18.63%
Multiple Factor Utility – Penelec, Mon Power, Potomac Edison, and West Penn	19.84%
Multiple Factor Utility – Jersey, Mon Power, Potomac Edison	20.18%
Multiple Factor Utility – AE only excluding transmission & MP Gen	28.03%
Multiple Factor Utility – All Mon Power and Potomac Edison	40.18%
Multiple Factor Utility – Met Ed and Potomac Edison	42.63%
Multiple Factor Utility – Mon Power and Potomac Edison	49.53%
<u>Multiple Factor Utility/Non-Utility</u>	
Multiple Factor-Utility/Non-Utility – Base (see CAM)	5.21%
Multiple Factor-Utility/Non-Utility – Excluding transmission and MP Gen	6.61%
<u>Number of Customers</u>	
Number of Customers – Base (see CAM)	6.87%
Number of Customers – Excluding GPU	11.01%
Number of Customers – WV	27.14%
<u>Transmission</u>	
Transmission – Sub Factor excluding MP Gen	2.99%
Transmission – Sub Factor excluding MP Gen and TrAIL Co	3.28%
Transmission – Sub Factor excluding Ohio, Penn Power and MP Gen	3.97%
Transmission – Sub Factor excluding Ohio, Penn Power, MP Gen & TrAIL Co	4.50%
Transmission – Sub Factor Mon Power, Potomac Edison, West Penn and MAIT	12.91%
Transmission – Sub Factor AE only excluding MP Gen	16.26%
Transmission – Sub Factor Potomac Edison & TrAIL	25.21%
Transmission – Sub Factor AE only excluding MP Gen and TrAIL Co	31.41%
<u>Direct Charge Ratio-Distribution Center EDC</u>	
Direct Charge Ratio-Distribution Center EDC - Base (See CAM)	9.26%
Direct Charge Ratio-Distribution Center EDC - Excluding Transmission	10.00%

FirstEnergy - Costs Allocated to Potomac Edison in 2021 by Allocation Factor and Expense Category

Allocation Factor	Labor	OTL	Grand Total
Multi-Factor Utility	$ 8,091,404.50	$ 1,272,912.37	$ 9,364,316.87
Multi-Factor All	$ 3,385,814.33	$ 3,972,426.13	$ 7,358,240.46
Number of Customers	$ 5,163,440.99	$ 1,370,670.82	$ 6,534,111.81
Multi-Factor Utility/Non-Utility	$ 396,202.37	$ 3,453,006.38	$ 3,849,208.75
Multi-Factor Utility/Transmission	$ 2,365,715.25	$ 256,566.91	$ 2,622,282.16
Direct Charge	$ 1,790,433.65	$ 437,373.81	$ 2,227,807.46
Participating Employees-General	$ 80,622.08	$ (14,877.30)	$ 65,744.78
Workstation Support	$ 32,324.61	$ 353.59	$ 32,678.20
Number of Computer Workstations	$ 27,045.76	$ 4,252.24	$ 31,298.00
Number of Shopping Customers	$ 19,307.06	$ 9,673.22	$ 28,980.28
Headcount	$ 3,850,418.70	$ (4,544,170.48)	$ (693,751.78)
Grand Total	**$ 25,202,729.30**	**$ 6,218,187.69**	**$ 31,420,916.99**

FirstEnergy Service Corporation
2021 Cost Allocation Manual

TABLE OF CONTENTS

I. **Introduction**

The purpose of this Cost Allocation Manual ("CAM") is to document the methods, policies and procedures that FirstEnergy Service Company ("FESC") will follow in performing services for affiliate companies. FESC was formed upon approval of the merger between GPU, Inc. and FirstEnergy Corp., and became operational June 1, 2003. FESC provides a variety of administrative, management, engineering, construction, environmental and support services for affiliated companies within the FirstEnergy system. Services are provided at fully allocated cost as documented in the executed Service Agreements between FESC and associate companies.

FirstEnergy is a diversified energy company that holds, directly or indirectly, all of the outstanding common stock of its principal subsidiaries: Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Pennsylvania Power Company (a wholly owned subsidiary of Ohio Edison), Jersey Central Power & Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, FirstEnergy Properties, FirstEnergy Ventures, FirstEnergy Fiber Holdings Corp, GPU Nuclear, Inc., Suvon LLC, FirstEnergy Service Company (FESC), Allegheny Energy Supply Company LLC, Monongahela Power Company, The Potomac Edison Company, West Penn Power Company and FirstEnergy Transmission, LLC and its principal subsidiaries (American Transmission Systems Incorporated, Trans-Allegheny Interstate Line Company, Mid-Atlantic Interstate Transmission, LLC and AET PATH Company, LLC), Green Valley Hydro, LLC, Allegheny Ventures, and Allegheny Energy Service Corporation (AESC)).

The books and records of FirstEnergy are kept in compliance with GAAP and Section 13(b)(2) of the Securities and Exchange Act of 1934 and where applicable, the regulations prescribed by the Federal Energy Regulatory Commission (FERC).

FESC and affiliate companies utilize SAP financial systems, an integrated accounting system in which costs are accumulated utilizing a work order management process. There are four cost collectors which are equivalent to work orders, they are: work breakdown structures (WBS), cost centers, orders and networks which are also used to accumulate costs and equate to the products and services provided. The work order system accumulates costs from employee time sheets, expense reports, overheads, allocations, vendor invoices, journal entries, etc. for later billing to affiliate company benefitting from the work performed. The SAP system also captures the home company (providing the service) and the charge company (receiving the service). The SAP system is set-up to ensure:

1. Separation of costs between regulated and non-regulated affiliates will be maintained.
2. Intercompany transactions and related billings are structured so that non-regulated activities are not subsidized by regulated affiliates.
3. Adequate audit trails exist on the books and records.

All employees of FESC are required to ensure time is distributed to the appropriate accounting structure by entering a timesheet. Direct charging of time is required where a specific affiliate company can be identified as the beneficiary of the services provided. Indirect charging is used secondarily. Supervisory review of timesheets is performed to assure that time charged is appropriate and cost collector used to bill the affiliate is proper.

II. General Description of Cost Allocation Methodology

FESC categorizes costs of services provided to affiliates into two categories, direct and indirect. Direct costs represent expenses incurred for activities and services identifiable as being applicable for the benefit of one affiliate or a group of affiliates captured through department work order systems for specific project billing purposes.

By the very nature of a service corporation, a portion of FESC's expenses will not be directly related to specific current operations or functions of individual Subsidiaries. Accordingly, it is necessary to develop formulae that recognize the overall contribution of FESC to both the current and future operations of the FirstEnergy system. After all direct charges have been made, the remaining costs (Indirect Costs) in each department in FESC must be fairly and equitably allocated among FirstEnergy and the Subsidiaries. The methodologies listed below pertain to all other costs which are not directly assigned but which make up the fully allocated cost of providing the product or service.

III. FirstEnergy Service Company Allocations

Multiple Factor – All - For the Indirect Costs for products or services benefiting the entire FirstEnergy system, FirstEnergy and all Subsidiaries bear a fair and equitable portion of such costs. FirstEnergy, Inc. bears 5% of these Indirect Costs. The remaining Indirect Costs are initially allocated between two groups, the Utility Subsidiaries and the Non-Utility Subsidiaries benefiting from the services provided based on FirstEnergy's equity investment in the respective groups. A subsequent allocation step then occurs. Among the Utility Subsidiaries, allocations are based upon the **Multiple Factor - Utility** method. Among the Non-Utility Subsidiaries, allocations are based upon the **Multiple Factor - Non-Utility** method.

Multiple Factor – Utility - For the Indirect Costs for a product or service solely benefiting one or more of the Utility Subsidiaries, each such Utility Subsidiary so benefiting is charged a portion of the Indirect Costs based on the average of its percentage share of the following three factors:

1. Gross transmission and/or distribution plant
2. Operating and maintenance expense excluding purchase power and fuel costs
3. Transmission and/or distribution revenues, excluding transactions with affiliates

These three (3) factors have been determined to be the most appropriate for the Utility Subsidiaries in the FirstEnergy system. Each factor is weighted equally so that no one facet of the electric utility operations inordinately influences the distribution of Indirect Costs.

Transmission Factor - Sub-set of Multi Factor-Utility using transmission revenue, transmission O&M, and transmission utility plant to allocate Transmission Support costs across the Utility Subsidiaries.

Multiple Factor - Non-Utility - For the Indirect Costs for products or services solely benefiting the Non-Utility Subsidiaries, each Non-Utility Subsidiary so benefiting receiving the product or service is charged a proportion of the Indirect Costs based upon the total assets of each Non-Utility Subsidiary, including any generating assets under operating leases to the Utility Subsidiaries.

Multiple Factor - Utility and Non-Utility - For the Indirect Costs for a product or service benefiting one or more of the Utility and Non-Utility Subsidiaries, each such Subsidiary so benefiting is first assigned a distribution ratio that is in proportion to the Indirect Costs based on FirstEnergy's equity investment in such Subsidiaries. Following this distribution, a subsequent allocation step occurs. Among the Utility Subsidiaries, allocations are based upon the **Multiple Factor-Utility**. Among the Non-Utility Subsidiaries, allocations are based upon **Multiple Factor - Non-Utility**

Direct Charge Ratio – The ratio of direct charges for a particular product or service to an individual Subsidiary as a percentage of the total direct charges for a particular product or service to all Subsidiaries benefiting from such services. Indirect Costs are then allocated to each Subsidiary based on the calculated ratios.

Headcount – Used to allocate Indirect Costs that are driven by headcount, like Human Resources department costs, Safety and employment-related legal matters. The calculation uses the total number of employees for the respective Subsidiary divided by the total number of employees.

Number of Participating Employees – General – Used to allocate Investment Management department costs and administrative fees for pension trust. Allocation driven by all participating employees within the pension and 401(k) plans. The calculation uses the number of participating employees for the respective Subsidiary divided by the total number of participating employees.

Number of Customers – For costs of products and services driven by the number of Utility distribution customers, the allocation method that is used is the number of Utility distribution customers for the respective Utility Subsidiary receiving the product or service divided by the total number of utility customers.

Number of Shopping Customers – A "shopping customer" is defined as a Utility customer who has selected a competitive electric generation supplier. For costs of products and services driven by the number of shopping customers, the allocation method that will be used will be the number of shopping customers for the respective Utility Subsidiary receiving the product or service divided by the total number of shopping customers.

Gigabytes Used – Number of gigabytes utilized by a Subsidiary receiving the product or service divided by the total number of gigabytes used by the FirstEnergy system companies applicable to that respective product or service.

Number of Computer Workstations – Number of computer workstations utilized by a Subsidiary receiving the product or service divided by the total number of computer workstations in use by the FirstEnergy system companies applicable to that respective product or service.

Number of Billing Inserts – Number of billing inserts performed for a Subsidiary receiving the product or service divided by the total number of billing inserts performed for the FirstEnergy system companies applicable to that respective product or service.

Daily Print Volume – Average daily print volume performed for a Subsidiary receiving the service divided by the total average daily print volume performed for the entire FirstEnergy system.

Number of Intel Servers – Number of Intel servers utilized by a Subsidiary receiving the product or service divided by the total number of Intel servers utilized by the FirstEnergy system.

Application Development – Number of application development hours budgeted for a Subsidiary receiving the service divided by the total number of budgeted application development hours for the year.

Server Support Composite – The average ratio of Unix gigabytes, SAP gigabytes and Intel number of servers for a Subsidiary receiving the service.

IV. FirstEnergy Service Company Allocation Codes – Allocation Percentages

Percentages shown include all companies included in calculation. FirstEnergy employs a methodology that permits inclusion or exclusion of companies within each methodology, depending upon the cost being allocated, so percentages within each method will vary by company depending on need.

Allocation Code	2021 %	Operating Company
Multiple Factor – All	14.54	Jersey Central Power & Light
	7.29	Pennsylvania Electric Company
	6.67	Metropolitan Edison Company
	12.48	Ohio Edison Company
	9.92	Cleveland Electric Illuminating Company
	4.23	Toledo Edison Company
	1.87	Pennsylvania Power Company
	10.40	American Transmission Sys, Inc.
	5.05	Monongahela Power - Delivery
	2.33	Monongahela Power - Generation
	4.95	Potomac Edison Company
	7.67	West Penn Power Company
	3.47	Trans-Allegheny Interstate Line Company
	3.80	Mid-Atlantic Interstate Transmission, LLC
	0.12	FE Ventures
	0.19	FE Properties
	0.02	AE Ventures
	5.00	FirstEnergy Holding Company
	100.00	Total
Multiple Factor-Utility	15.62	Jersey Central Power & Light
	7.83	Pennsylvania Electric Company
	7.16	Metropolitan Edison Company
	13.41	Ohio Edison Company
	10.66	Cleveland Electric Illuminating Company
	4.54	Toledo Edison Company
	2.01	Pennsylvania Power Company
	10.18	American Transmission Sys, Inc.
	5.42	Monongahela Power - Delivery
	2.50	Monongahela Power - Generation
	5.32	Potomac Edison Company
	8.24	West Penn Power Company
	3.39	Trans-Allegheny Interstate Line Company
	3.72	Mid-Atlantic Interstate Transmission, LLC
	100.00	Total
Multi-Factor Utility -	10.32	Jersey Central Power & Light
Transmission	11.18	Ohio Edison Company
	9.04	Cleveland Electric Illuminating Company

	4.14	Toledo Edison Company
	0.06	Pennsylvania Power Company
	32.39	American Transmission Sys, Inc
	2.72	Monongahela Power - Delivery
	1.28	Monongahela Power - Generation
	2.95	Potomac Edison Company
	3.72	West Penn Power Company
	8.75	Trans-Allegheny Interstate Line Company
	13.45	Mid-Atlantic Interstate Transmission, LLC
	100.00	Total
Multiple Factor-Non	36.86	FE Ventures
Utility	57.06	FE Properties
	0.21	Suvon, LLC
	5.87	AE Ventures
	100.00	Total
Multiple Factor -	15.31	Jersey Central Power & Light
Utility/Non-Utility	7.67	Pennsylvania Electric Company
	7.02	Metropolitan Edison Company
	13.14	Ohio Edison Company
	10.45	Cleveland Electric Illuminating Company
	4.45	Toledo Edison Company
	1.97	Pennsylvania Power Company
	10.95	American Transmission Sys, Inc.
	5.31	Monongahela Power - Delivery
	2.45	Monongahela Power - Generation
	5.21	Potomac Edison Company
	8.07	West Penn Power Company
	3.65	Trans-Allegheny Interstate Line Company
	4.00	Mid-Atlantic Interstate Transmission, LLC
	0.13	FE Ventures
	0.20	FE Properties
	0.02	AE Ventures
	100.00	Total
Headcount	17.37	Jersey Central Power & Light
	9.63	Pennsylvania Electric Company
	8.19	Metropolitan Edison Company
	14.82	Ohio Edison Company
	11.70	Cleveland Electric Illuminating Company
	4.72	Toledo Edison Company
	2.47	Pennsylvania Power Company
	14.38	Monongahela Power - Delivery
	7.11	Potomac Edison Company
	9.61	West Penn Power Company

	100.00	Total
Participating Employees-	11.54	Cleveland Electric Illuminating Company
General	17.56	Jersey Central Power & Light
	8.26	Metropolitan Edison Company
	14.73	Ohio Edison Company
	9.83	Pennsylvania Electric Company
	2.52	Pennsylvania Power Company
	4.67	Toledo Edison Company
	14.36	Monongahela Power - Delivery
	6.93	Potomac Edison Company
	9.60	West Penn Power Company
	100.00	Total
Number of Customers	17.21	Ohio Edison Company
	2.73	Pennsylvania Power Company
	12.26	Cleveland Electric Illuminating Company
	5.11	Toledo Edison Company
	18.62	Jersey Central Power & Light
	9.38	Metropolitan Edison Company
	9.55	Pennsylvania Electric Company
	6.40	Monongahela Power - Delivery
	6.87	Potomac Edison Company
	11.87	West Penn Power Company
	100.00	Total
Number of Shopping	31.48	Ohio Edison Company
Customers	1.83	Pennsylvania Power Company
	24.54	Cleveland Electric Illuminating Company
	9.37	Toledo Edison Company
	9.81	Jersey Central Power & Light
	7.08	Metropolitan Edison Company
	6.50	Pennsylvania Electric Company
	1.72	Potomac Edison Company
	7.67	West Penn Power Company
	100.00	Total
Application Development-	No Longer Used	
Application Development RTS	No Longer Used	
Direct Charge Ratio -	15.53	Jersey Central Power & Light
Emergency Management	2.86	Pennsylvania Electric Company

System (January-March)	2.62	Metropolitan Edison Company
	4.90	Ohio Edison Company
	3.90	Cleveland Electric Illuminating Company
	1.66	Toledo Edison Company
	0.74	Pennsylvania Power Company
	30.81	American Transmission Sys, Inc.
	4.57	Monongahela Power - Delivery
	4.75	Potomac Edison Company
	6.55	West Penn Power Company
	8.32	Trans-Allegheny Interstate Line Company
	12.79	Mid-Atlantic Interstate Transmission, LLC
	100.00	Total
Direct Charge Ratio -	15.54	Jersey Central Power & Light
Emergency Management	2.88	Pennsylvania Electric Company
System (April-December)	2.64	Metropolitan Edison Company
	4.94	Ohio Edison Company
	3.93	Cleveland Electric Illuminating Company
	1.67	Toledo Edison Company
	0.74	Pennsylvania Power Company
	30.72	American Transmission Sys, Inc.
	4.58	Monongahela Power - Delivery
	4.76	Potomac Edison Company
	6.56	West Penn Power Company
	8.29	Trans-Allegheny Interstate Line Company
	12.75	Mid-Atlantic Interstate Transmission, LLC
	100.00	Total
Gigabytes Used – SAP	No Longer Used	
Gigabytes Used – Unix	No Longer Used	
Number of Billing Inserts	18.62	Jersey Central Power & Light
	9.55	Pennsylvania Electric Company
	9.38	Metropolitan Edison Company
	17.21	Ohio Edison Company
	12.26	Cleveland Electric Illuminating Company
	5.11	Toledo Edison Company
	2.73	Pennsylvania Power Company
	6.40	Monongahela Power - Delivery
	6.87	Potomac Edison Company
	11.87	West Penn Power Company
	100.00	Total

Application Development		
Network Service	No Longer Used	
Number of Intel Servers	No Longer Used	
Number of Computer	15.15	Jersey Central Power & Light
Workstations	9.90	Pennsylvania Electric Company
	10.39	Metropolitan Edison Company
	15.35	Ohio Edison Company
	11.41	Cleveland Electric Illuminating Company
	5.20	Toledo Edison Company
	2.85	Pennsylvania Power Company
	10.79	Monongahela Power - Delivery
	8.19	Potomac Edison Company
	10.77	West Penn Power Company
	100.00	Total
Daily Print Volume	18.62	Jersey Central Power & Light
	9.55	Pennsylvania Electric Company
	9.38	Metropolitan Edison Company
	17.21	Ohio Edison Company
	12.26	Cleveland Electric Illuminating Company
	5.11	Toledo Edison Company
	2.73	Pennsylvania Power Company
	6.40	Monongahela Power - Delivery
	6.87	Potomac Edison Company
	11.87	West Penn Power Company
	100.00	Total
Server Support Composite	No Longer Used	
Number of Computer	15.15	Jersey Central Power & Light
Workstations - Support	9.90	Pennsylvania Electric Company
	10.39	Metropolitan Edison Company
	15.35	Ohio Edison Company
	11.41	Cleveland Electric Illuminating Company
	5.20	Toledo Edison Company
	2.85	Pennsylvania Power Company
	10.79	Monongahela Power - Delivery
	8.19	Potomac Edison Company
	10.77	West Penn Power Company
	100.00	Total
Direct Charge Ratio -	17.56	Jersey Central Power & Light

Environmental Akron	14.69	Pennsylvania Electric Company
	3.17	Metropolitan Edison Company
	1.46	Monongahela Power - Delivery
	39.13	Monongahela Power - Generation
	1.63	Ohio Edison Company
	3.59	Cleveland Electric Illuminating Company
	0.20	Toledo Edison Company
	0.99	Pennsylvania Power Company
	0.23	Potomac Edison Company
	1.57	West Penn Power Company
	0.28	Trans-Allegheny Interstate Line Company
	2.93	Mid-Atlantic Interstate Transmission, LLC
	12.57	American Transmission Sys, Inc.
	100.00	Total
Direct Charge Ratio -	4.76	Jersey Central Power & Light
Environmental Reading	0.27	Pennsylvania Electric Company
	13.01	Metropolitan Edison Company
	1.56	Monongahela Power - Delivery
	2.05	Monongahela Power - Generation
	6.16	Ohio Edison Company
	7.41	Cleveland Electric Illuminating Company
	0.09	Toledo Edison Company
	8.16	Potomac Edison Company
	56.53	Mid-Atlantic Interstate Transmission, LLC
	100.00	Total
Direct Charge Ratio -	20.32	Jersey Central Power & Light
Environmental Billing ED	7.41	Pennsylvania Electric Company
	4.33	Metropolitan Edison Company
	2.53	Ohio Edison Company
	3.25	Cleveland Electric Illuminating Company
	0.44	Toledo Edison Company
	0.84	Pennsylvania Power Company
	3.02	Potomac Edison Company
	7.81	Monongahela Power - Delivery
	25.26	American Transmission Sys, Inc.
	3.82	Trans-Allegheny Interstate Line Company
	10.65	Mid-Atlantic Interstate Transmission, LLC
	10.32	West Penn Power Company
	100.00	Total
Direct Charge Ratio -	8.37	Monongahela Power - Delivery
Environmental GRBG	57.69	Monongahela Power - Generation
(January – October)	2.17	Potomac Edison Company
	9.28	American Transmission Sys, Inc.

	0.56	Jersey Central Power & Light
	0.24	Metropolitan Edison Company
	0.82	Ohio Edison Company
	0.25	Cleveland Electric Illuminating Company
	0.06	Toledo Edison Company
	0.34	Pennsylvania Electric Company
	0.34	Pennsylvania Power Company
	11.66	West Penn Power Company
	4.59	Trans-Allegheny Interstate Line Company
	3.63	Mid-Atlantic Interstate Transmission, LLC
	100.00	Total
Direct Charge Ratio -	10.14	Monongahela Power - Delivery
Environmental GRBG	69.93	Monongahela Power - Generation
(November – December)	2.63	Potomac Edison Company
	0.68	Jersey Central Power & Light
	0.29	Metropolitan Edison Company
	1.00	Ohio Edison Company
	0.30	Cleveland Electric Illuminating Company
	0.07	Toledo Edison Company
	0.41	Pennsylvania Electric Company
	0.41	Pennsylvania Power Company
	14.14	West Penn Power Company
	100.00	Total
Direct Charge Ratio -	1.72	Monongahela Power - Delivery
Environmental Field Ops	42.98	Monongahela Power - Generation
	1.47	Potomac Edison Company
	1.40	Metropolitan Edison Company
	1.68	Ohio Edison Company
	1.48	Cleveland Electric Illuminating Company
	1.16	Toledo Edison Company
	0.40	Pennsylvania Power Company
	1.97	West Penn Power Company
	43.82	American Transmission Sys, Inc.
	0.45	Trans-Allegheny Interstate Line Company
	1.47	Mid-Atlantic Interstate Transmission, LLC
	100.00	Total
Direct Charge Ratio -	33.14	Jersey Central Power & Light
Broad Street Rent	16.65	Pennsylvania Electric Company
	15.19	Metropolitan Edison Company
	6.34	Ohio Edison Company
	5.03	Cleveland Electric Illuminating Company
	2.13	Toledo Edison Company
	0.97	Pennsylvania Power Company

	4.52	American Transmission Sys, Inc.
	3.08	Monongahela Power - Delivery
	1.01	Monongahela Power - Generation
	2.59	Potomac Edison Company
	3.93	West Penn Power Company
	1.51	Trans-Allegheny Interstate Line Company
	1.65	Mid-Atlantic Interstate Transmission, LLC
	0.03	FE Ventures
	0.01	AE Ventures
	0.05	FE Properties
	2.17	FirstEnergy Holding Company
	100.00	Total
Direct Charge Ratio -	53.37	Jersey Central Power & Light
Distribution Center-EDC	24.47	Metropolitan Edison Company
	5.34	Pennsylvania Electric Company
	9.26	Potomac Edison Company
	7.56	Mid-Atlantic Interstate Transmission, LLC
	100.00	Total
Direct Charge Ratio -	16.12	Pennsylvania Electric Company
Distribution Center - SDC	26.61	Monongahela Power - Delivery
	12.79	Potomac Edison Company
	40.47	West Penn Power Company
	4.01	Mid-Atlantic Interstate Transmission, LLC
	100.00	Total
Direct Charge Ratio -	10.74	Jersey Central Power & Light
Unit Dispatch	81.85	Monongahela Power - Generation
(January – February)	4.60	Potomac Edison Company
	2.81	Pennsylvania Electric Company
	100.00	Total
Direct Charge Ratio -	94.61	Monongahela Power - Generation
Unit Dispatch	5.39	Potomac Edison Company
(March – December)	100.00	Total
Direct Charge Ratio -	1.44	American Transmission Sys, Inc.
BETA Mgr/Chemistry	1.15	Trans-Allegheny Interstate Line Company
	1.29	Mid-Atlantic Interstate Transmission, LLC
	14.29	Cleveland Electric Illuminating Company
	2.42	Jersey Central Power & Light
	2.45	Metropolitan Edison Company
	5.74	Monongahela Power - Delivery
	29.96	Monongahela Power - Generation
	16.39	Ohio Edison Company

	0.40	Potomac Edison Company
	6.21	Pennsylvania Electric Company
	3.51	Pennsylvania Power Company
	3.66	Toledo Edison Company
	11.09	West Penn Power Company
	100.00	Total
Direct Charge Ratio -	2.90	American Transmission Sys, Inc.
BETA Fire & Safety	2.32	Trans-Allegheny Interstate Line Company
	2.61	Mid-Atlantic Interstate Transmission, LLC
	15.41	Cleveland Electric Illuminating Company
	0.97	Jersey Central Power & Light
	1.20	Metropolitan Edison Company
	6.96	Monongahela Power - Delivery
	16.96	Monongahela Power - Generation
	21.25	Ohio Edison Company
	0.04	Potomac Edison Company
	6.92	Pennsylvania Electric Company
	4.62	Pennsylvania Power Company
	4.41	Toledo Edison Company
	13.43	West Penn Power Company
	100.00	Total
Direct Charge Ratio -	9.14	Allegheny Energy Supply
BETA AESupply & ED	1.31	American Transmission Sys, Inc.
	1.05	Trans-Allegheny Interstate Line Company
	1.18	Mid-Atlantic Interstate Transmission, LLC
	12.98	Cleveland Electric Illuminating Company
	2.19	Jersey Central Power & Light
	2.23	Metropolitan Edison Company
	5.22	Monongahela Power - Delivery
	27.23	Monongahela Power - Generation
	14.89	Ohio Edison Company
	0.36	Potomac Edison Company
	5.64	Pennsylvania Electric Company
	3.19	Pennsylvania Power Company
	3.32	Toledo Edison Company
	10.07	West Penn Power Company
	100.00	Total
Direct Charge Ratio -	2.65	American Transmission Sys, Inc.
BETA - ED	2.12	Trans-Allegheny Interstate Line Company
	2.38	Mid-Atlantic Interstate Transmission, LLC
	20.05	Cleveland Electric Illuminating Company
	3.39	Jersey Central Power & Light
	3.44	Metropolitan Edison Company

	8.06	Monongahela Power - Delivery
	23.00	Ohio Edison Company
	0.58	Potomac Edison Company
	8.71	Pennsylvania Electric Company
	4.93	Pennsylvania Power Company
	5.13	Toledo Edison Company
	15.56	West Penn Power Company
	100.00	Total
Direct Charge Ratio -	10.60	Allegheny Energy Supply
BETA – Corp Facilities	12.40	Cleveland Electric Illuminating Company
(January – June)	2.40	Jersey Central Power & Light
	1.50	Metropolitan Edison Company
	8.40	Monongahela Power - Delivery
	30.30	Monongahela Power - Generation
	12.60	Ohio Edison Company
	0.80	Potomac Edison Company
	6.70	Pennsylvania Electric Company
	2.60	Pennsylvania Power Company
	3.70	Toledo Edison Company
	8.00	West Penn Power Company
	100.00	Total
Direct Charge Ratio -	4.71	Allegheny Energy Supply
BETA – Corp Facilities	0.09	Allegheny Generating Company
(July – December)	15.61	Cleveland Electric Illuminating Company
	2.22	Jersey Central Power & Light
	1.93	Metropolitan Edison Company
	5.82	Monongahela Power - Delivery
	30.95	Monongahela Power - Generation
	13.36	Ohio Edison Company
	2.05	Potomac Edison Company
	6.97	Pennsylvania Electric Company
	3.42	Pennsylvania Power Company
	4.22	Toledo Edison Company
	8.65	West Penn Power Company
	100.00	Total

Cost Allocation Manual

Certification of Training Program

I am the Vice President, Controller and Chief Accounting Officer for FirstEnergy Service Company that supplies accounting services to the operating affiliates in the FirstEnergy System including The Potomac Edison Company. I am familiar with the FirstEnergy Service Company Cost Allocation Manual (CAM), which Potomac Edison files with the Commission pursuant to the requirements of Code of Maryland Regulations (COMAR) 20.40.02.07.B. I hereby certify that the personnel responsible for accounting for transactions involving Potomac Edison and its affiliates in the FirstEnergy System are familiar with and are trained on the requirements of the CAM as necessary to comply with the provisions of the Maryland Commission's affiliate regulations.

Jason J. Lisowski
Vice President, Controller and
Chief Accounting Officer

Verification

I declare under the penalties of perjury that the foregoing statements are true and correct to the best of my knowledge, information and belief.

Jason J. Lisowski
Vice President, Controller and
Chief Accounting Officer

STATE OF OHIO

COUNTY OF Stark :

I, Kristina A. Housley a notary public in and for the State of Ohio, hereby certify that Jason J. Lisowski signed the foregoing verification statement as Vice President, Controller and Chief Accounting Officer of FirstEnergy Service Company as agent for The Potomac Edison Company and has acknowledged the same before me in my presence on the 28th day of June, 2022.

NOTARIAL SEAL
STATE OF OHIO

KRISTINA A. HOUSLEY
NOTARY PUBLIC • STATE OF OHIO
My Commission Expires Mar. 24, 2027

Kristina A. Housley
Notary Public

My commission expires: 3/24/2027

Cost Allocation Manual

Affidavit Relating to Cost Allocation and Asset Transfer Pricing Principles

I am Vice President, Controller and Chief Accounting Officer for FirstEnergy Service Company that supplies accounting services to the operating affiliates in the FirstEnergy System including The Potomac Edison Company (Potomac Edison). As such Vice President, Controller and Chief Accounting Officer, I am familiar with the FirstEnergy Service Company Cost Allocation Manual (CAM), which Potomac Edison files with the Commission pursuant to the requirements of Code of Maryland Regulations (COMAR) 20.40.02.07.B. I hereby certify that to the best of my knowledge, information and belief, the cost allocation and asset transfer pricing principles set forth in FirstEnergy Service Company's CAM comply with COMAR Title 20, Subtitle 40.

Jason J. Lisowski
Vice President, Controller and
Chief Accounting Officer

Verification

I declare under the penalties of perjury that the foregoing statements are true and correct to the best of my knowledge, information and belief.

Jason J. Lisowski
Vice President, Controller and
Chief Accounting Officer

STATE OF OHIO

COUNTY OF Stark :

I, Kristina A. Housley a notary public in and for the State of Ohio, hereby certify that Jason J. Lisowski signed the foregoing verification statement as Vice President, Controller and Chief Accounting Officer of FirstEnergy Service Company as agent for The Potomac Edison Company, and has acknowledged the same before me in my presence on the 28th day of June, 2022.

NOTARIAL SEAL
STATE OF OHIO

KRISTINA A. HOUSLEY
NOTARY PUBLIC • STATE OF OHIO
My Commission Expires Mar. 24, 2027

Kristina A. Housley
Notary Public

My commission expires: 3/24/2027

FirstEnergy Corp.

Somerhalder II, John W.	Vice Chair and Executive Director
Strah, Steven E.	President and Chief Executive Officer
Park, Hyun	Senior Vice President and Chief Legal Officer
Taylor, K. Jon	Senior Vice President, Chief Financial Officer and Strategy
Lisowski, Jason J.	Vice President, Controller and Chief Accounting Officer

The Potomac Edison Company

Belcher, Samuel L.	President
Park, Hyun	Senior Vice President and General Counsel
Taylor, K. Jon	Senior Vice President and Chief Financial Officer
Lisowski, Jason J.	Vice President and Controller

Allegheny Energy Service Corporation

Strah, Steven E.	President
Park, Hyun	Senior Vice President and General Counsel
Staub, Steven R.	Vice President and Treasurer

FirstEnergy Service Company

Strah, Steven E.	President and Chief Executive Officer
Belcher, Samuel L.	Senior Vice President, Operations
Taylor, K. Jon	Senior Vice President, Chief Financial Officer and Strategy
Walker, Christine L.	Senior Vice President and Chief Human Resources Officer
Lisowski, Jason J.	Vice President, Controller and Chief Accounting Officer

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

WALTER S. LARNERD

Concerning: Low-Income Assistance Initiatives

March 22, 2023

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Walter S. Larnerd, and my business address is 5001 NASA Blvd, Fairmont, West Virginia.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by FirstEnergy Service Company as Manager, Revenue Operations Strategy. In that capacity, I oversee the administration of the human services programs including the Electric Universal Service Program ("EUSP"), the Maryland Energy Assistance Program ("MEAP")/Utility Service Protection Program ("USPP"), and assistance grants for The Potomac Edison Company ("PE" or "Company"). I also oversee additional processes such as bankruptcy, security deposits and revenue assurance functions.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in management and economics from SUNY Empire State College. Over the last 14 years, I have held a number of positions in the Customer Service organization at FirstEnergy which have included Supervisor, Customer Contact Center and Supervisor, Revenue Assurance. Most recently, I was appointed to the Manager, Revenue Operations Strategy position in 2022. In my current role, I oversee Human Services programs, energy efficiency programs and support back-office tasks for revenue assurance functions.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. I am testifying on behalf of PE in support of its distribution base rate case filing. More specifically, my testimony addresses the two new low-income assistance initiatives for residential customers that PE is proposing.

II. LOW INCOME ASSISTANCE INITIATIVES

Q. PLEASE DISCUSS THE NEW INITIATIVES THAT PE IS PROPOSING TO FURTHER ASSIST LOW-INCOME CUSTOMERS.

A. The Company is proposing two new initiatives for residential customers. I will discuss each in turn. The first is the "Energy Assistance Outreach Team." The purpose of the team is to increase awareness, education and participation in energy assistance programs that are available to low-income customers. The team will partner with targeted organizations and strengthen the relationships within the community.

Q. WHAT SPECIFIC ACTIVITIES WILL THE TEAM ASSIST CUSTOMERS WITH?

A. On a broad level, the team will assist low-income residential customers with learning about and applying for assistance programs that will help with their utility costs. More specifically, the team will:

1) Be responsible for education, resources, tools, and technology needed to reduce and/or eliminate customer barriers to program participation;
2) Work with customers, agencies, local charities, churches and local governments to understand the types of available programs;

3) Help customers by sharing what information is required to participate in the different programs;
4) Participate in energy assistance fairs and organize additional events as necessary; and
5) Be a support system for agencies to assist with special situations or barriers.

Q. WHY IS PE PROPOSING THE ENERGY ASSISTANCE OUTREACH TEAM?

A. A centralized, dedicated team to assist customers with information about enrollment in all the assistance programs will be a benefit to customers by helping eligible customers receive available assistance in paying their electric bills.

Q. WHAT IS THE ANNUAL BUDGET FOR THE ENERGY ASSISTANCE OUTREACH TEAM?

A. PE's annual budget for this initiative is $202,433.

Q. WHAT ARE THE COMPONENTS OF THE ANNUAL BUDGET?

A. Staffing, program materials and travel expenses are the main budget components.

Q. WILL PE HAVE DEDICATED TEAM MEMBERS FOR ITS SERVICE TERRITORY?

A. Yes, there will be two people dedicated full time to the PE service territory.

Q. HAS PE REACHED OUT TO OTHER ENERGY ASSISTANCE GROUPS IN MARYLAND TO MAKE THEM AWARE OF THIS INITIATIVE?

A. Not yet, since the Maryland Public Service Commission ("Commission") has not yet approved the new program. Every year PE conducts a meeting with local energy assistance agencies and other stakeholders to coordinate efforts and make those stakeholders aware of the PE programs, personnel, and resources which the agencies and stakeholders can work with in assisting customers. This year's meeting was held on March 10, 2023, and was attended by Religious Coalition for Emergency Human Needs, City of Frederick Housing and Human Services, Washington County Community Action Council, Maryland Department of Housing and Community Development, Allegany County Department of Social Services, Office of Home Energy Programs, Montgomery County Department of Health and Human Services, and the Office of People's Counsel. PE made a presentation about current Company programs at that meeting. This new program, if approved by the Commission, would have incremental costs and be additive to what was described in the meeting.

Q. WHAT IS THE SECOND INITIATIVE?

A. The second initiative is called the "50% Discount Program."

Q. WHY IS PE PROPOSING THIS PROGRAM?

A. PE is proposing the 50% Discount Program in response to House Bill 606, a bill entitled Electricity and Gas - Limited-Income Mechanisms and Assistance. My understanding is that the bill was introduced in the Maryland General Assembly on January 20, 2021, and enacted May 30, 2021. The bill authorizes utilities to adopt a low-income mechanism to benefit certain low-income eligible customers subject to the approval of the Commission.

Q. PLEASE EXPLAIN WHAT THIS PROGRAM WILL ENTAIL.

A. The 50% Discount program will provide a 50% monthly discount to distribution charges at the primary residence of income-eligible residential customers during a five-month period beginning November 1 through March 31, i.e., during the winter heating period.

The discount will be applied as a credit to distribution charges on the participating customer's monthly bill.

Q. HOW WAS THE DISCOUNT SET AT 50%?

A. The discount was set at 50% based on a similar program that is currently used in PE's West Virginia service territory. It was then internally tested using data from the PE Maryland customer base. There are approximately 12,800 PE residential customers that have participated in currently-available programs (EUSP, MEAP/USPP). When the discount was applied to the average monthly distribution charges for this set of customers during the above-mentioned five-month period, the average monthly discount was $13.09. The total average annual discount per customer was $65.47 – provided during the 5-month period of November through March.

Q. WHAT ARE THE ELIGIBILITY CRITERIA FOR THIS PROGRAM?

A. There are two eligibility criteria as follows:

1) Customers may only receive the discount for their primary residence.
2) Customers who enroll in an energy assistance program (EUSP, MEAP/USPP) will be enrolled in the program. This second criterion has the added advantage of serving as another incentive for customers to take advantage of those programs, especially at a time when PE will be working (as discussed earlier in my testimony) to help such customers navigate the enrollment processes.

Q. HOW WILL CUSTOMERS ENROLL IN THIS PE 50% DISCOUNT PROGRAM?

A. Customers who enroll in an energy assistance program will automatically be enrolled. This allows the Company to provide the discount to confirmed low-income residential customers without administrative costs for a separate application and enrollment process. This also allows the customer to receive the benefit without going through a separate enrollment process. The enrollment would be triggered with the receipt of the assistance program or grant via a batch enrollment file to the Company. If the customer transfers service within the PE service territory the enrollment will also transfer to the new premise.

Q. HOW WILL THE EFFECTIVENESS OF THE PROGRAM BE MONITORED?

A. PE will conduct a quarterly review on the discount program to measure the dollars included in the discount and the impact on the customer's ability to pay, including impacts on those customers' arrearages, disconnections, and resulting uncollectibles. A successful program should reduce arrearages and uncollectibles and help keep more customers on service.

Q. WHAT IS PE'S BUDGET FOR THIS INITIATIVE?

A. The annual PE budget for this initiative is $840,000, virtually all of which represents the discounts to the eligible customers.

Q. WHEN DOES PE PLAN TO ROLL OUT BOTH THE ENERGY ASSISTANCE OUTREACH TEAM AND THE 50% DISCOUNT PROGRAM?

A. The Company expects to commence these programs during 2024, subject to the receipt of regulatory approvals.

III. CONCLUSION

Q. PLEASE SUMMARIZE THE NEW LOW-INCOME ASSISTANCE INITIATIVES BEING PROPOSED BY PE FOR COMMISSION CONSIDERATION AND APPROVAL.

A. PE is proposing: (1) a new "Energy Assistance Outreach Team"; and (2) a "50% Discount Program." The "Energy Assistance Outreach Team" is designed to increase awareness, education and participation in energy assistance programs that are available to low-income residential customers at a budgeted annual incremental cost of $202,433; whereas the "50% Discount Program" will provide a 50% monthly discount to distribution charges at the primary residence of income-eligible residential customers during the five-month winter period at a budgeted annual incremental cost of $840,000. The total cost for these two low-income residential initiatives is $1,042,433. Cost recovery for these two new initiatives is explained in the direct testimony of Company witness Valdes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

BEFORE THE

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OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

DYLAN W. D'ASCENDIS, CRRA, CVA

PARTNER, SCOTTMADDEN, INC.

Concerning: Overall Cost of Capital and Credit-Adjusted Risk-Free Rate

March 22, 2023

TABLE OF CONTENTS

I. INTRODUCTION AND BACKGROUND

A. Witness Identification

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 200, Mount Laurel, NJ 08054.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Partner at ScottMadden, Inc.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have offered expert testimony on behalf of investor-owned utilities before over 35 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the Alberta Utility Commission, an American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst" by NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are shown in Appendix A.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony is to present evidence on behalf of The Potomac Edison Company ("PE" or the "Company") and recommend an allowed rate of return on common equity ("ROE") for its Maryland jurisdictional rate base. I also calculate and recommend a credit-adjusted risk free rate.

Q. HAVE YOU PREPARED SCHEDULES IN SUPPORT OF YOUR RECOMMENDATION?

A. Yes. I have prepared Exhibit No. 1, which consists of Schedules DWD-1 through DWD-11, which were prepared by me or under my direction.

Q. WHAT IS YOUR RECOMMENDED ROE FOR PE?

A. I recommend that the Maryland Public Service Commission (the "PSC" or "Commission") authorize PE the opportunity to earn an ROE of 10.60% on its jurisdictional rate base. The ratemaking capital structure and cost of long-term debt is sponsored by Company Witness Wang. The overall rate of return is summarized on page 1 of Schedule DWD-1 and in Table 1 below:

Table 1: Summary of Recommended Weighted Average Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.47%	4.018%	1.87%
Common Equity	53.53%	10.60%	5.67%
Total	100.00%		7.54%

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR RECOMMENDED COMMON EQUITY COST RATE.

A. My recommended common equity cost rate of 10.60% is summarized on page 2 of Schedule DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to PE. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be

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1 *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope").
2 *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922) ("Bluefield").

an evaluation of relative risk between the company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from applying several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the market data of a proxy group of 13 electric utilities ("Utility Proxy Group") whose selection criteria will be discussed below. Although I have not included the results in determining the recommended ROE, I have also applied these same models to a Non-Price Regulated Proxy Group,[3] which I demonstrate is similar in total risk to the Utility Proxy Group. The results of the models based on the Non-Price Regulated Proxy Group serve as a check on the reasonableness of my other analytical models. The results derived from each are as follows:

[3] The development of the Non-Price Regulated Proxy Group is explained in more detail in Section V, part D.

Table 2: Summary of Common Equity Cost Rates

Discounted Cash Flow Model	9.29%
Risk Premium Model	11.64%
Capital Asset Pricing Model	11.79%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.58%
Indicated Range of Common Equity Cost Rates Before Adjustments	10.04% - 11.04%
Business Risk Adjustment	0.15%
Credit Risk Adjustment	0.10%
Flotation Cost Adjustment	0.19%
Indicated Cost of Common Equity Cost Rates After Adjustment	10.29% - 11.29%
Recommended Cost of Common Equity	10.60%

The indicated common equity cost rates across these models is from 10.04% to 11.04% before any Company-specific adjustments.[4] I then adjusted the indicated common equity cost rate upward by 0.15% and 0.10% to reflect the Company's smaller relative size and riskier bond rating, as compared to the Utility Proxy Group companies.[5] These adjustments result in a Company-specific range of indicated common equity cost rates between 10.29% and 11.29%. From this range, I recommend that the Commission authorize an ROE of 10.60% for the Company.

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4 My indicated range of common equity cost rates are 50 basis points above and below the midpoint of my three model results.

5 My indicated range of common equity cost rates after adjustment does not include flotation costs.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

A. The remainder of my Direct Testimony is organized as follows:

- *Section III* – Provides a summary of financial theory and regulatory principles pertinent to the development of the Cost of Capital;
- *Section IV* – Explains my selection of the Utility Proxy Group used to develop my analytical results;
- *Section V* – Describes the analyses on which my recommendation is based;
- *Section VI* – Summarizes my common equity cost rate before adjustments to reflect Company-specific factors;
- *Section VII* – Explains my adjustments to my common equity cost rate to reflect the Company-specific factors;
- *Section VIII*– Presents my conclusions regarding ROE; and
- *Section IX* – Calculates and recommends a credit-adjusted risk-free rate ("CARFR").

III. GENERAL PRINCIPLES

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST RATE?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, *i.e.,* the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[6]

In summary, the U.S. Supreme Court has found that a return should be adequate to attract capital at reasonable terms and enable the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate

6 *Hope*, 320 U.S. 591, 603 (1944).

with the returns expected elsewhere for investments of equivalent risk. The Commission's decision in this proceeding, therefore, should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Lastly, the required return for a regulated public utility is established on a stand-alone basis, i.e., for the utility operating company at issue in a rate case. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting process. That is, utility holding companies that own many utility operating companies have choices as to where they will invest their capital within the holding company family. Therefore, the opportunity cost concept applies regardless of whether the funding source is public or corporate.

When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, and with other similar risk companies, which may include non-utilities. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE for the Company reflects the risks and prospects of its operations and supports its financial integrity from a stand-alone perspective. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational (i.e., business risk) and financing (i.e., financial risk) of the Company's utility operations on a stand-alone basis.

Marketplace data must be relied on in assessing a common equity cost rate appropriate for ratemaking purposes. Just as the use of the market data for the proxy group adds reliability to the informed expert's judgment used in arriving at a recommended common equity cost rate, the use of multiple, generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF CAPITAL ESTIMATED IN REGULATORY PROCEEDINGS?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (i.e., rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." The principle of opportunity costs recognizes that investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative investment opportunities with comparable risks. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

The cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities. However, the cost of equity is not directly observable and must be estimated based on market data and various financial models. Because the cost of equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require considering the subject company's business and financial risks, and the returns available on comparable investments.

A. <u>Business Risk</u>

Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks generally faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, operations, capital intensity, size, the degree of operating leverage, emerging technologies including distributed energy resources, the vagaries of weather, and the like, all of which have a direct bearing on earnings.

Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. When determining an appropriate return on common equity, the relevant issue is where investors see the subject company in relation to other similarly situated utility companies (i.e., the Utility Proxy Group). To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate and reliable service (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds. The obligation to serve and the corresponding need to access capital is even more acute during period of capital market distress.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. Financial Risk

Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT IN DETERMINING A FAIR RATE OF RETURN.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (i.e., failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk.

Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (I.E., INVESTMENT RISK)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (i.e., total risk) faced by bond investors.[7] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

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[3] Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, e.g., within the A category, an S&P rating can by at A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, e.g., within the A category, a Moody's rating can be A1, A2 and A3.

IV. PE AND THE UTILITY PROXY GROUP

Q. WHY IS IT NECESSARY TO DEVELOP A PROXY GROUP WHEN ESTIMATING THE ROE FOR PE?

A. Because PE is not publicly traded and does not have publicly traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for the Company. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company: a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It therefore is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses and necessarily must consider the sort of quantitative and qualitative information discussed throughout my Direct Testimony. Additionally, a relative risk analysis between the Company and the Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group indicated results.

My analyses are based on the Utility Proxy Group, containing U.S. electric utilities. As discussed earlier, utilities must compete for capital with other companies with commensurate risk (including non-utilities) and, to do so, must be provided the opportunity to earn a fair and reasonable return. Consequently, it is appropriate to consider the Utility Proxy Group's market data in determining the Company's ROE.

Q. ARE YOU FAMILIAR WITH PE'S OPERATIONS?

A. Yes. PE owns and operates an electric transmission and distribution system in portions of Maryland and West Virginia and owns a transmission system in a portion of northern Virginia.[8] The operations subject to this proceeding are the electric distribution operations in Maryland, which serve approximately 285,000 customers. PE is not publicly-traded but rather is an operating subsidiary of FirstEnergy Corp. ("FE" or the "Parent"), which operates in six states[9] and serves approximately six million customers and is publicly-traded under symbol FE.

Q. PLEASE EXPLAIN HOW YOU CHOSE THE COMPANIES IN THE UTILITY PROXY GROUP.

A. Because the cost of equity is a comparative exercise, my objective in developing a proxy group was to select companies that are comparable to the Company. Because

8 The Company serves approximately 285,000 customers in Maryland and approximately 150,000 customers in West Virginia.

9 FirstEnergy Corp., 2021 SEC Form 10-K, at 1. In addition to Maryland, FE also serves customers in Ohio, Pennsylvania, West Virginia, New Jersey, and New York.

the Company is a 100% rate-regulated electric transmission and distribution utility, I applied the following criteria to select my Utility Proxy Group:

(i) They were included in the Eastern, Central, or Western Electric Utility Group of *Value Line Investment Survey* (Standard Edition)(*"Value Line"*);

(ii) They have 70% or greater of fiscal year 2021 total operating income derived from, and 70% or greater of fiscal year 2021 total assets attributable to, regulated electric distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (i.e., one publicly-traded utility merging with or acquiring another) or any other major development;

(iv) They have not cut or omitted their common dividends during the five years ending 2021 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted Beta coefficients ("beta");

(vi) They have positive *Value Line* five-year dividends per share ("DPS") growth rate projections; and

(vii) They have *Value Line*, Zacks, or Yahoo! Finance consensus five-year earnings per share ("EPS") growth rate projections.

The following 13 companies met these criteria:

Table 3: Utility Proxy Group Companies

Company Name	Ticker Symbol
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Corporation	AEP
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
Eversource Energy	ES
IDACORP, Inc.	IDA
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Portland General Electric Company	POR
Xcel Energy Inc.	XEL

V. COMMON EQUITY COST RATE MODELS

Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE MARKET-BASED?

A. Yes. As discussed previously, regulated public utilities, like the Company, must compete for equity in capital markets along with all other companies with commensurate risk, including non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those companies. If an individual investor is choosing to invest their capital among companies with comparable risk, they will choose the company providing a higher return over a company providing a lower return.

Q. ARE THE COST OF COMMON EQUITY MODELS YOU USE MARKET-BASED MODELS?

A. Yes. The DCF model is market-based in that market prices are used in developing the dividend yield component of the model. The RPM and CAPM are also market-based in that the bond/issuer ratings and expected bond yields/risk-free rate used in the application of the RPM and CAPM reflect the market's assessment of bond/credit risk. In addition, the use of beta to determine the equity risk premium also reflects the market's assessment of market/systematic risk, as betas are derived from regression analyses of market prices. Moreover, market prices are used in the development of the monthly returns and equity risk premiums used in the Predictive Risk Premium Model ("PRPM"). Selection criteria for the Non-Price Regulated Proxy Group are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE THE COMPANY'S ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I apply to the Utility Proxy Group described above. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on multiple models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the specific models on which I rely focus on different aspects of return requirements, and provide different insights into investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk Premium-based methods (*i.e.,* the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the ROE. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

A. Discounted Cash Flow Model

Q. PLEASE DESCRIBE THE DCF MODEL, GENERALLY.

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate; i.e., the total common equity return rate expected by investors, as shown in Equation [1] below:

$$K_e = (D_0\ (1+g))/P + g$$

where:

K_e = the required Return on Equity;

D_0 = the annualized Dividend Per Share;

P = the current stock price; and

g = the growth rate.

Q. WHICH VERSION OF THE DCF MODEL DO YOU USE?

A. I used the single-stage constant growth DCF model.

Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE CONSTANT GROWTH DCF MODEL.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of December 30, 2022, divided by the average closing market price for the 60 trading days ended December 30, 2022.[10]

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.

A. Because dividends are paid periodically (*e.g.,* quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Schedule DWD-2 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 5.

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10 *See*, Column 1, page 1 of Schedule DWD-2.

Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY TO THE UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF MODEL.

A. Investors with more limited resources than institutional investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and Yahoo! Finance. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.

A. As shown on page 1 of Schedule DWD-2, the application of the Constant Growth DCF model to the Utility Proxy Group results in a wide range of indicated ROEs from 6.70% to 12.65%. The mean of those results is 9.24%, the median result is 9.34%, and the average of the mean and median result is 9.29%. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the

Utility Proxy Group, I relied on an average of the mean and the median results (i.e., 9.29%) of the DCF. By doing so, I have considered the DCF results for each company without giving undue weight to outliers on either the high or low side.

B. The Risk Premium Model

Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. PLEASE EXPLAIN HOW YOU DERIVED YOUR INDICATED COST OF COMMON EQUITY BASED ON THE RPM.

A. To derive my indicated cost of common equity under the RPM, I used two risk premium methods. The first method was the Predictive Risk Premium Model ("PRPM") and the second method was a risk premium model using a total market approach. The PRPM estimates the risk-return relationship directly, while the total market approach indirectly derives a risk premium by using known metrics as a proxy for risk.

1. Predictive Risk Premium Model

Q. PLEASE EXPLAIN THE PRPM.

A. The PRPM, published in the *Journal of Regulatory Economics,*[11] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility" or ARCH.[12] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility of prices and returns clusters over time and is therefore highly predictable and can be used to predict future levels of risk and risk premiums. That is, historical volatility can be used to predict future volatility, which then can be translated to a predicted equity risk premium.

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[11] Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, Ph.D. "A New Approach for Estimating the Equity Risk Premium for Public Utilities", The Journal of Regulatory Economics (December 2011), 40:261-278.

[12] Autoregressive conditional heteroscedasticity; *See also,* www.nobelprize.org.

Q. HOW DOES THE PRPM ESTIMATE THE INVESTOR REQUIRED RETURN?

A. The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on an evaluation of the results of that behavior (i.e., the variance of historical equity risk premiums).

Q. PLEASE EXPLAIN YOUR APPLICATION OF THE PRPM.

A. The inputs to the model are the historical returns on the common shares of each Utility Proxy Group company minus the historical monthly yield on long-term U.S. Treasury securities through December 2022. Using a generalized form of ARCH, known as GARCH, I calculated each Utility Proxy Group company's projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series[13] and a GARCH coefficient.[14] Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[15] produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield of 3.91%[16] to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. The 30-year U.S. Treasury bond yield is a consensus forecast derived from *Blue Chip*.[17]

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13 Illustrated on Columns 1 and 2, page 2 of Schedule DWD-3.

14 Illustrated on Column 4, page 2 of Schedule DWD-3.

15 Annualized Return = (1 + Monthly Return) ^12 – 1.

16 *See,* Column 6, page 2 of Schedule DWD-3.

17 *Blue Chip Financial Forecasts ("Blue Chip")*, January 1, 2023 at 2 and December 1, 2022 at 14.

Q. WHAT ARE THE RESULTS OF THE PRPM AS APPLIED TO THE UTILITY PROXY GROUP?

A. The mean PRPM indicated common equity cost rate for the Utility Proxy Group is 11.99%, the median is 11.90%, and the average of the two is 11.95%. Consistent with my reliance on the average of the median and mean results of the DCF models, I relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 11.95%.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As shown in Exhibits DWD-3 and DWD-4, the risk-free rate adopted for applications of the RPM and CAPM is 3.91%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2024, and long-term projections for the years 2024 to 2028 and 2029 to 2033.

Q. WHY DO YOU USE THE PROJECTED 30-YEAR TREASURY YIELD IN YOUR ANALYSES?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (i.e., cost of capital) will be applied.

In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

More specifically, the term of the risk-free rate used for cost of capital purposes should match the life (or duration) of the underlying investment (i.e., perpetuity). As noted by Morningstar:

> The traditional thinking regarding the time horizon of the chosen Treasury security is that it should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[18]

Morin also confirms this when he states:

> [b]ecause common stock is a long-term investment and because the cash flows to investors in the form of dividends last indefinitely, the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM and Risk Premium methods (footnote omitted)… The expected common stock return is based on long-term cash flows, regardless of an individual's holding time period.[19]

Pratt and Grabowski recommend a similar approach to selecting the risk-free rate: "[i]n theory, when determining the risk-free rate and the matching ERP you should be matching the risk-free security and the ERP with the period in which the investment cash flows are expected."[20]

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18 Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 44.

19 Roger A. Morin, Modern Regulatory Finance, Public Utility Reports, Inc., 2021, at 169. ("Morin").

20 Shannon Pratt and Roger Grabowski, Cost of Capital: Applications and Examples, 3rd Ed. (Hoboken, NJ: John Wiley & Sons, Inc., 2008), at 92. "ERP" is the Equity Risk Premium.

As a practical matter, equity securities represent a perpetual claim on cash flows; 30-year Treasury bonds are the longest-maturity securities available to approximate that perpetual claim. Thus, the use of a 30-year Treasury bond yield is a more appropriate risk-free rate as it more accurately reflects the life of the assets it finances.

2. Total Market Approach Risk Premium Model

Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, (2) an equity risk premium based on the S&P Utilities Index, and (3) an equity risk premium based on authorized ROEs for electric utilities.

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE EXPECTED BOND YIELD APPLICABLE TO THE UTILITY PROXY GROUP.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including the common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. Because I am unaware of any publication that provides forecasted public utility bond yields, I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the second calendar quarter of 2024, and *Blue Chip's* long-term projections for 2024 to 2028, and 2029 to 2033. As shown on line 1, page 3 of Schedule DWD-3, the average expected yield on Moody's Aaa-rated corporate bonds is 5.05%.

Because that 5.05% estimate represents a corporate bond yield and not a utility specific bond yield, I adjusted the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield. That resulted in an upward adjustment of 0.83%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds.[21] Adding that recent 0.83% spread to the expected Aaa-rated corporate bond yield of 5.05% results in an expected A2-rated public utility bond yield of 5.88%.

I then reviewed the average credit rating for the Utility Proxy Group from Moody's to determine if an adjustment to the estimated A2-rated public utility bond was necessary. Since the Utility Proxy Group's average Moody's long-term issuer rating is Baa1, another adjustment to the expected A2-rated public utility bond is needed to reflect the difference in bond ratings. An upward adjustment of 0.20%, which represents two-thirds of a recent spread between A2-rated and Baa2-rated public utility bond yields, is necessary to make the A2-rated prospective bond yield applicable to an Baa1-rated public utility bond.[22] Adding the 0.20% to the 5.88% prospective A2-rated public utility bond yield results in a 6.08% expected bond yield applicable to the Utility Proxy Group.

[21] As shown on line 2 and explained in note 2, page 3 of Schedule DWD-3.
[22] As shown on line 4 and explained in note 3, page 3 of Schedule DWD-3.

Table 4: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[23]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip)*	5.05%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.83%
Adjustment to Reflect the Utility Proxy Group's Average Moody's Bond Rating of Baa1	0.20%
Prospective Bond Yield Applicable to the Utility Proxy Group	6.08%

To develop the total market approach RPM estimate of the appropriate return on equity, this prospective bond yield is then added to the average of the three different equity risk premiums, which I now discuss, in turn.

a. Beta-Derived Equity Risk Premium

Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.

A. The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) the beta. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 9, page 8 of Schedule DWD-3. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, two *Value Line*-based equity risk premiums and a Bloomberg-based equity risk premium. Each of these is described below.

[23] As shown on page 3 of Exhibit DWD-3.

Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON LONG-TERM HISTORICAL DATA?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks from the Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2022 ("SBBI - 2022")[24] less the average historical yield on Moody's Aaa/Aa2-rated corporate bonds for the period 1928 to 2021. Using holding period returns over a very long time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, i.e., a company expected to operate in perpetuity.

SBBI's long-term arithmetic mean monthly total return rate on large company common stocks was 12.11% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa2-rated corporate bonds was 5.98%.[25] As shown on line 1, page 8 of Schedule DWD-3, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 6.13%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa2-rated corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in SBBI - 2022.[26] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide

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24 *See,* SBBI-2022 Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2021.
25 As explained in note 1, page 9 of Schedule DWD-3.
26 SBBI - 2022, at page 201.

insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED MARKET EQUITY RISK PREMIUM.

A. To derive the regression-based market equity risk premium of 7.26% shown on line 2, page 8 of Schedule DWD-3, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa2-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa2-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa2-rated corporate bonds yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa2})$$

Q. PLEASE EXPLAIN THE DERIVATION OF THE PRPM EQUITY RISK PREMIUM.

A. I used the same PRPM approach described above to the PRPM equity risk premium. The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa2-rated corporate bonds during the period from January 1928 through December 2022.[27] Using the previously-discussed generalized form of ARCH, known as GARCH, the projected equity risk premium is determined using Eviews© statistical software. The resulting PRPM predicted a market equity risk premium of 9.76%.[28]

Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON *VALUE LINE* DATA FOR YOUR RPM ANALYSIS.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 8 of Schedule DWD-3. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended December 30, 2022, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line*'s Standard Edition.[29]

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27 Data from January 1926 to December 2021 is from SBBI - 2022. Data from January 2022 to December 2022 is from Bloomberg.
28 Shown on line 3, page 8 of Schedule DWD-3.
29 As explained in detail in note 1, page 2 of Schedule DWD-3.

The average median expected price appreciation is 71%, which translates to a 14.35% annual appreciation, and, when added to the average of *Value Line's* median expected dividend yields of 2.23%, equates to a forecasted annual total return rate on the market of 16.58%. The forecasted Moody's Aaa-rated corporate bond yield of 5.05% is deducted from the total market return of 16.58%, resulting in an equity risk premium of 11.53%, as shown on line 4, page 8 of Schedule DWD-3.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON THE S&P 500 COMPANIES.

A. Using data from *Value Line*, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 15.67%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.05% results in a 10.62% projected equity risk premium.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON BLOOMBERG DATA.

A. Using data from Bloomberg, I calculated an expected total return on the S&P 500 using expected dividend yields and long-term growth estimates as a proxy for capital appreciation, identical to the method described above. The expected total return for the S&P 500 is 11.06%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.05% results in a 6.01% projected equity risk premium.

Q. WHAT IS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK PREMIUM FOR USE IN YOUR RPM ANALYSIS?

A. I gave equal weight to all six equity risk premiums based on each source - historical, *Value Line*, and Bloomberg - in arriving at an 8.55% equity risk premium.

Table 5: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[30]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa2-Rated Corporate Bond Yields (1928 – 2021)	6.13%
Regression Analysis on Historical Data	7.26%
PRPM Analysis on Historical Data	9.76%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	11.53%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected Aaa Corporate Bond Yields	10.62%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected Aaa Corporate Bond Yields	6.01%
Average	8.55%

After calculating the average market equity risk premium of 8.55%, I adjusted it by beta to account for the risk of the Utility Proxy Group. As discussed below, beta is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Schedule DWD-4, the average of the mean and median beta for the Utility Proxy Group is 0.78. Multiplying the 0.78 average beta by the market equity risk

30 As shown on page 8 of Exhibit DWD-3.

premium of 8.55% results in a beta-adjusted equity risk premium for the Utility Proxy Group of 6.67%.

b. S&P Utility Index Derived Equity Risk Premium

Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P UTILITY INDEX AND MOODY'S A2-RATED PUBLIC UTILITY BONDS?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the S&P Utilities Index, using *Value Line* and Bloomberg data, respectively. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.74% and monthly Moody's A2-rated public utility bond yields of 6.46% from 1928 to 2021 to arrive at an equity risk premium of 4.28%.[31] I then used the same historical data to derive an equity risk premium of 4.80% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to December 2022 to arrive at a PRPM-derived equity risk premium of 5.56% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 9.50% and 9.20% using data from *Value Line* and Bloomberg, respectively, and subtracted

[31] As shown on line 1, page 12 of Schedule DWD-3.

the prospective Moody's A2-rated public utility bond yield of 5.88%,[32] which resulted in equity risk premiums of 3.62% and 3.32%, respectively. As with the market equity risk premiums, I averaged each risk premium based on each source (i.e., historical, *Value Line*, and Bloomberg) to arrive at my utility-specific equity risk premium of 4.32%.

Table 6: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[33]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2021)	4.28%
Regression Analysis on Historical Data	4.80%
PRPM Analysis on Historical Data	5.56%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P Utilities Index less Projected A2 Utility Bond Yields	3.62%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P Utilities Index less Projected A2 Utility Bond Yields	3.32%
Average	4.32%

c. Authorized Return Derived Equity Risk Premium

Q. HOW DO YOU DERIVE AN EQUITY RISK PREMIUM OF 4.77% BASED ON AUTHORIZED ROEs FOR ELECTRIC UTILITIES?

A. The equity risk premium of 4.77% shown on line 3, page 7 of Schedule DWD-3 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds. That analysis is shown on page 13

32 Derived on line 3, page 3 of Schedule DWD-3.
33 As shown on page 12 of Exhibit DWD-3.

of Schedule DWD-3. Page 13 of Schedule DWD-3 contains the graphical results of a regression analysis of 1,207 rate cases for electric utilities which were fully litigated during the period from January 1, 1980 through December 31, 2022. It shows the implicit equity risk premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision.

It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature on the subject.[34] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds. Given the expected A2-rated utility bond yield of 5.88%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.77%, which is shown on line 3, page 7 of Schedule DWD-3.

Q. WHAT IS YOUR CONCLUSION OF AN EQUITY RISK PREMIUM FOR USE IN YOUR TOTAL MARKET APPROACH RPM ANALYSIS?

A. The equity risk premium I apply to the Utility Proxy Group is 5.25%, which is the average of the beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premiums of 6.67%, 4.32%, and 4.77%, respectively.[35]

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34 *See*, *e.g.*, Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at pages 11 to 12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at pages 33 to 45.

35 As shown on page 7 of Schedule DWD-3.

Q. WHAT IS THE INDICATED RPM COMMON EQUITY COST RATE BASED ON THE TOTAL MARKET APPROACH?

A. As shown on line 7, page 3 of Schedule DWD-3 and shown on Table 7, below, I calculated a common equity cost rate of 11.33% for the Utility Proxy Group based on the total market approach RPM.

Table 7: Summary of the Total Market Return Risk Premium Model[36]

Prospective Moody's A3/Baa1-Rated Utility Bond Applicable to the Utility Proxy Group	6.08%
Prospective Equity Risk Premium	5.25%
Indicated Cost of Common Equity	11.33%

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE PRPM AND THE TOTAL MARKET APPROACH RPM?

A. As shown on page 1 of Schedule DWD-3, the indicated RPM-derived common equity cost rate is 11.64%, which gives equal weight to the PRPM (11.95%) and the adjusted-market approach results (11.33%).

C. The Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by beta (β). A beta less than 1.0 indicates lower variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

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36 As shown on page 3 of Exhibit DWD-3.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the beta. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta\,(R_m - R_f)$$

Where:	R_s	=	Return rate on the common stock
	R_f	=	Risk-free rate of return
	R_m	=	Return rate on the market as a whole
	β	=	Adjusted beta (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have measured the extent to which security returns and beta are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the beta is related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[37] The ECAPM reflects this empirical reality.

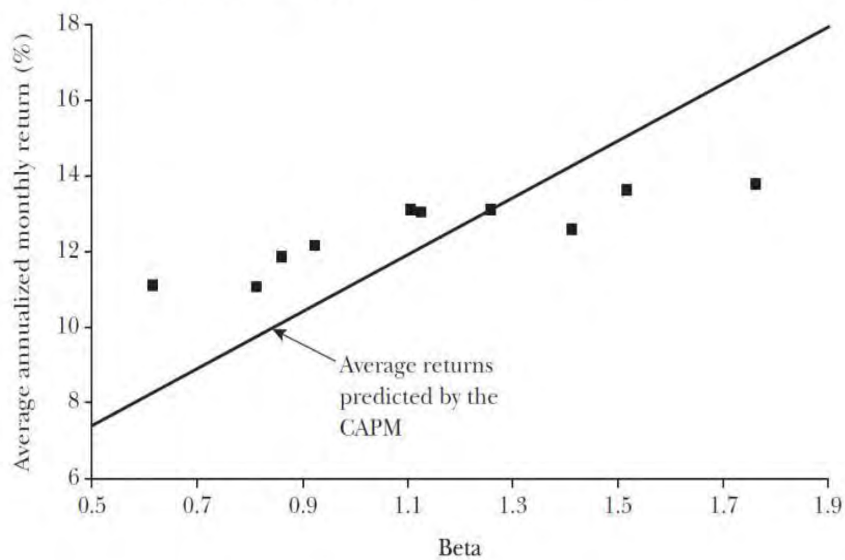
[37] Morin, at page 220.

Q. WHY IS THE USE OF THE ECAPM APPROPRIATE IN DETERMINING THE ROE FOR PE?

The ECAPM is a well-established model that has been relied on in both academic and regulatory settings. Fama and French clearly state regarding Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low." [38]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

[38] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004 at 33 "Fama & French".

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[39]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,\beta(R_M - R_F) + (1-x)\ \beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$[40]

Fama and French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[41]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the highest beta is 16.8 percent per year; the actual is 13.7 percent.[42]

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39 Morin, at 207.
40 Morin, at 221.
41 Fama & French, at 32.
42 Fama & French, at 33.

Research from Dianna R. Harrington also supports the use of the ECAPM. Harrington summarizes studies on the predicted results of the CAPM versus the actual returns in her text Modern Portfolio Theory & the Capital Asset Pricing Model:

> So far we have learned some very interesting things about the CAPM and reality. Some of the earliest work tested realized data (history) against data generated by simulated portfolios. Early studies by Douglas (1969) and Lintner (Douglas [1969]) showed discrepancies between what was expected on the basis of the CAPM and the actual relationships that were apparent in the capital markets. Theoretically, the minimal rate of return from the portfolios (the intercept) and the actual risk-free rate for the period should have been equal. They were not.
>
> * * *
>
> Another study, now more famous than Lintner's was done by Black, Jensen, and Scholes (1972). Lintner had used what is called a cross-sectional method (looking at a number of stock returns during one time period), whereas Black, Jensen, and Scholes used a time-series method (using returns for a number of stocks over several time periods). To make their test, Black, Jensen, and Scholes assumed that what had happened in the past was a good proxy for the investor expectations (a frequent assumption in CAPM tests). Using historical data, they generated estimates using what we call the market model:
>
> $$R_{jt} = \alpha_j + \beta_j (R_{mt}) + \varepsilon_j$$
>
> Where:
>
> R = total returns
>
> β = the slope of the line (the incremental return for risk)
>
> α = the intercept or a constant (expected to be 0 over time and across all firms)
>
> ε = an error term (expected to be random, without information)
>
> m = the market proxy
>
> j = the firm or portfolio
>
> t = the time period

> Instead of using single stocks, they formed portfolios in an effort to wash out one source of error; because betas of single firms are quite unstable. On the basis of the CAPM, they expected to find
>
> 1. That the intercept was equal to the risk-free rate (their proxy was the Treasury bill rate)
> 2. That the capital market line had a positive slope and that riskier (higher beta) securities provided higher return
>
> Instead they found
>
> 1. That the intercept was different from the risk-free rate
> 2. That high-risk securities earned less and low-risk securities earned more than predicted by the model
> 3. That the intercept seemed to depend on the beta of any asset: high-beta stocks had a different intercept than low-beta stocks
>
> * * *
>
> Fama and MacBeth (1974) criticized the Black, Jensen, and Scholes study (hereafter called BJS). In a reformation of the study, they supported the first of the BJS findings. They found that the intercept exceeded the risk-free proxy, but did not find the evidence to support the other BJS conclusions.[43]

Harrington discusses Black's potential solution to this phenomenon:

> Black's replacement for the risk-free asset was a portfolio that had no covariability with the market portfolio. Because the relevant risk in the CAPM is systematic risk, a risk-free asset would be the one with no volatility relative to the market – that is, a portfolio with a beta of zero. All investor-perceived levels of risk could be obtained from various linear combinations of Black's zero-beta portfolio and the market portfolio… Since R_z (the rate of return of the zero-beta asset) and R_m are uncorrelated (as R_f and R_m were assumed to be in the simple CAPM), the

[43] Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 43-45.

investor can choose from various combinations of R_z and R_m. On segment R_mY, R_z, is sold short and proceeds are invested in R_m. On segment R_zR_m, portions of the zero-beta portfolio are purchased. At R_m, the investor is fully invested in the market portfolio. The equilibrium CAPM was rewritten by Black as follows:

$$E\,(R_i) = (1 - \beta_i)\,E\,(R_z) + \beta_i E(R_m)$$

Where:

E indicates expected,
$E\,(R_z)$ is less than $E(R_m)$, and
R_z holdings over the whole market must be in equilibrium. That is, the number of short sellers and lenders of securities must be equal.

Black's adaptation is intriguing. The result of using this model is a capital market line that has a less steep slope and a higher intercept than those of the simple CAPM. If Black's model is more correct in its description of investor behavior in the marketplace, then the use of the simple model would produce equity return predictions that would be too low for stocks with betas greater than one and too high for stocks with betas of less than one.[44]

Clearly, the justification from Morin, Fama and French, and Harrington, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In addition, the New York Public Service Commission has been using this form of the CAPM, with factors of 0.25 and 0.75, since the mid-1990s. As such, the ECAPM is a well-established model that has been relied on in both academic and regulatory settings. I continue to believe it is an appropriate model to estimate PE's ROE, and in view of theory and practical research, I have applied

[44] Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 43-45.

both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

Q. WHAT BETA COEFFICIENTS DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the beta in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg Professional Services. While both of those services adjust their calculated (or "raw") betas to reflect the tendency of beta to regress to the market mean of 1.00, *Value Line* calculates beta over a five-year period, while Bloomberg calculates it over a two-year period.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As described previously, the risk-free rate adopted for both applications of the CAPM is 3.91%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2024, and long-term projections for the years 2024 to 2028 and 2029 to 2033.

Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM FOR THE MARKET USED IN YOUR CAPM ANALYSES.

A. The basis of the market risk premium is explained in detail in note 1 on Schedule DWD-4. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, two *Value Line* data-based market risk premiums, and one Bloomberg data-based market risk premium.

The long-term income return on U.S. Government securities of 5.02% was deducted from the SBBI - 2022 monthly historical total market return of 12.37%, which results in an historical market equity risk premium of 7.35%.[45] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities from SBBI - 2022. That regression analysis yielded a market equity risk premium of 8.71%. The PRPM market equity risk premium is 10.86%, and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through December 2022.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 3.91%, discussed above, from the *Value Line* projected total annual market return of 16.58%, resulting in a forecasted total market equity risk premium of 12.67%. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the projected risk-free rate of 3.91% from the projected total return of the S&P 500 of 15.67%. The resulting market equity risk premium is 11.76%.

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 3.91% from the projected total return of the S&P 500 of 11.06%. The resulting market equity risk premium is 7.15%. These six measures, when averaged, result in an average total market equity risk premium of 9.75%.

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45 SBBI - 2022, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21).

Table 8: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[46]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2021)	7.35%
Regression Analysis on Historical Data	8.71%
PRPM Analysis on Historical Data	10.86%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	12.67%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected 30-Year Treasury Bond Yields	11.76%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected 30-Year Treasury Bond Yields	7.15%
Average	9.75%

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL AND EMPIRICAL CAPM TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Schedule DWD-4, the mean result of my CAPM/ECAPM analyses is 11.80%, the median is 11.78%, and the average of the two is 11.79%. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 11.79%.

46 As shown on page 2 of Exhibit DWD-4.

D. Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM, and CAPM

Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC, NON-PRICE REGULATED COMPANIES?

A. Although I am not an attorney, my interpretation of the *Hope* and *Bluefield* cases is that they did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Utility Proxy Group, since all of these companies compete for capital in the exact same markets.

Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the betas and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (i.e., five years). These selection criteria resulted in a proxy group of 50 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line Investment Survey* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, i.e., not utilities;

(iii) Their betas must lie within plus or minus two standard deviations of the average unadjusted betas of the Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted betas must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Betas measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar betas <u>and</u> similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. HAVE YOU PREPARED A SCHEDULE WHICH SHOWS THE DATA FROM WHICH YOU SELECTED THE 50 DOMESTIC, NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. Yes, the basis of my selection and both proxy groups' regression statistics are shown in Schedule DWD-5.

Q. IS THE USE OF UNADJUSTED BETAS AND STANDARD ERRORS OF THE REGRESSION SUPPORTED BY ACADEMIC AND FINANCIAL LITERATURE?

A. Yes, it is. Business and financial risks may vary between companies and proxy groups, but if the collective average betas and standard errors of the regression of the group are similar, then the total, or aggregate, non-diversifiable market risks and diversifiable risks are similar, as noted in "Comparable Earnings: New Life for an Old Precept" provided in Schedule DWD-6.[47] Thus, because the non-price regulated companies are selected based on analyses of market data, they are comparable in total risk (even though individual risks may vary) to the Utility Proxy Group. This is demonstrated clearly on page 273 of Jack C. Francis' Investments: Analysis and Management (page 3 of Schedule DWD-7), which shows that total risk can be "partitioned into its systematic and unsystematic components." Essentially, companies that have similar betas and standard errors of regression have similar total investment risk.

[47] Frank J. Hanley, Pauline M. Ahern, *Comparable Earnings: New Life for an Old Precept*, Financial Quarterly Review, Summer 1994.

Q. IN ADDITION TO YOUR SELECTION CRITERIA, HAVE YOU CONDUCTED ADDITIONAL STUDIES TO SHOW THAT THE NON-PRICE REGULATED PROXY GROUP IS SIMILAR IN TOTAL RISK TO YOUR UTILITY PROXY GROUP?

A. Yes, I have. *Value Line's* Safety Ranking is a proxy for total risk.[48] As shown in Table 9, below, my Non-Price Regulated Group is similar in total risk to my Utility Proxy Group:

Table 9: Risk Assessment of Non-Price Regulated Proxy Group and Utility Proxy Groups Using *Value Line* Metric

Group	Safety Rank
Utility Proxy Group	1.88
Non-Price Reg. Proxy Group	1.96

Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF MODEL, RPM, AND CAPM FOR THE NON-PRICE REGULATED PROXY GROUP?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where

48 *Value Line* also ranks stocks for Safety by analyzing the total risk of a stock compared to the approximately 1,700 stocks in the *Value Line* universe. Each of the stocks tracked in the *Value Line* Investment Survey is ranked in relationship to each other, from 1 (the highest rank) to 5 (the lowest rank). Safety is a quality rank, not a performance rank, and stocks ranked 1 and 2 are most suitable for conservative investors; those ranked 4 and 5 will be more volatile. Volatility means prices can move dramatically and often unpredictably, either down or up. The major influences on a stock's Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

I did not use public utility-specific equity risk premiums, nor did I apply the PRPM to the individual non-price regulated companies.

Page 2 of Schedule DWD-8 derives the Constant Growth DCF model common equity cost rate. As shown, the indicated common equity cost rate is 11.72%.

Pages 3 through 5 of Schedule DWD-8 contain the data and calculations that support the 13.40% RPM common equity cost rate. As shown on line 1, page 3 of Schedule DWD-8, the consensus prospective yield on Moody's Baa-rated corporate bonds for the six quarters ending in the second quarter of 2024, and for the years 2024 to 2028 and 2029 to 2033, is 6.05%.[49] Since the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of Baa1, a downward adjustment of 0.17% to the projected Baa2-rated corporate bond yield is necessary to reflect a difference in ratings which results in a projected Baa1-rated corporate bond yield of 5.88% for the Non-Regulated Proxy group.

When the beta-adjusted risk premium of 7.52%[50] relative to the Non-Price Regulated Proxy Group is added to the prospective Baa1-rated corporate bond yield of 5.88%, the indicated RPM common equity cost rate is 13.40%.

Page 6 of Schedule DWD-8 contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 12.59%.

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49 *Blue Chip Financial Forecasts*, January 1, 2023 at 2 and December 1, 2022 at 14.
50 Derived on page 5 of Schedule DWD-8.

Q. HOW IS THE COST RATE OF COMMON EQUITY BASED ON THE NON-PRICE REGULATED PROXY GROUP COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Schedule DWD-8, the results of the common equity models applied to the Non-Price Regulated Proxy Group -- which group is comparable in total risk to the Utility Proxy Group -- are as follows: 11.72% (DCF), 13.40% (RPM), and 12.59% (CAPM). The average of the mean and median of these models is 12.58%, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.

VI. CONCLUSION OF COMMON EQUITY COST RATE BEFORE ADJUSTMENTS

Q. WHAT IS THE INDICATED COMMON EQUITY COST RATE BEFORE ADJUSTMENTS?

A. By applying multiple cost of common equity models to the Utility Proxy Group and the Non-Price Regulated Proxy Group, the indicated range of common equity cost rates attributable to the Utility Proxy Group before any relative risk adjustments is between 10.04% and 11.04%. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because each of these models is theoretically sound and available to investors, and because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

Based on these common equity cost rate results, I conclude that a range of common equity cost rates between 10.04% and 11.04% is reasonable and appropriate before any adjustments for relative risk differences between PE and the Utility Proxy Group are made.

VII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

A. Size Adjustment

Q. DOES PE'S SMALLER SIZE RELATIVE TO THE UTILITY PROXY GROUP COMPANIES INCREASE ITS BUSINESS RISK?

A. Yes. PE's smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base. This is true for utilities, as well as for non-regulated companies.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Kroll's Cost of Capital Navigator: U.S. Cost of Capital Module ("Kroll") discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," Kroll states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[51]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 14, they note:

> . . . the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[52]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

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51 Kroll, Cost of Capital Navigator: U.S. Cost of Capital Module, Size as a Predictor of Equity Returns, at 1.

52 Fama & French, at 25-43.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[53] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms**. (emphasis added)[54]

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of PE, including its small relative size, which is justified and supported above by evidence in the financial literature.

Q. DO CREDIT RATING AGENCIES HAVE A MINIMUM SIZE CRITERION FOR A GIVEN RATING LEVEL?

A. No, they do not. S&P states in its "General Corporate Methodology, Section 2: Analyzing Subfactors for Scale, Scope, and Diversity", that there is no minimum size criterion, although size often provides a measure of diversification. Size and

53 Brealey, Richard A. and Myers, Stewart C., Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

54 Brigham, Eugene F., Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

> scope of operations is important relative to those of industry peers, though not in absolute terms. While relatively smaller companies can enjoy a high degree of diversification, they will likely be, almost by definition, more concentrated in terms of product, number of customers, or geography, than their larger peers in the same industry.[55]

Moody's, in its "Ratings Methodology for Regulated Electric and Gas Companies" states that size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the scorecard attempts to incorporate the first two of these into Factors [diversification], for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks.[56]

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55 Standard & Poor, "General Corporate Methodology, Section 2: Analyzing Subfactors for Scale, Scope, and Diversity", at 60.

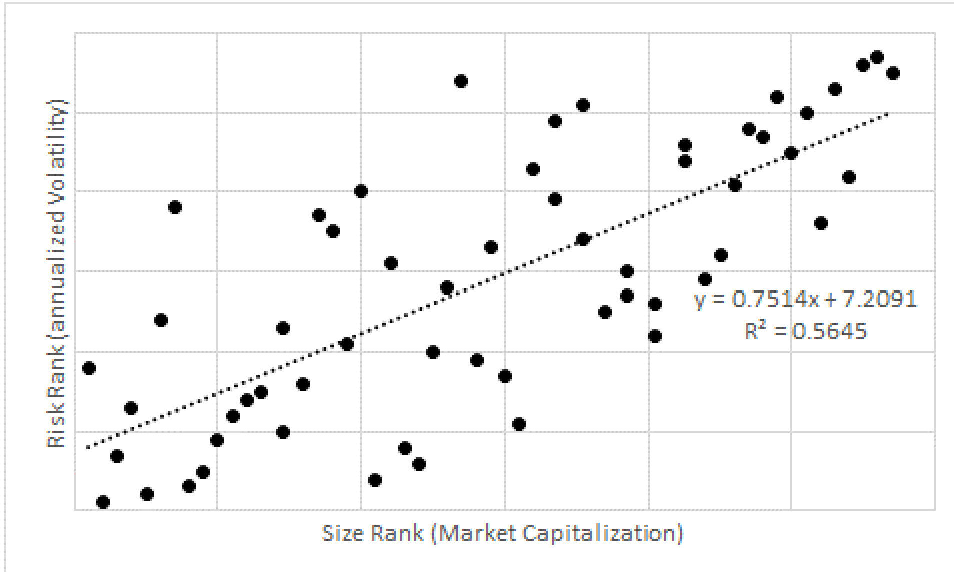
56 Moody's, "Ratings Methodology for Regulated Electric and Gas Companies", at 26-27.

The above statements by S&P and Moody's reinforce that they do not specifically take size into account (i.e.., there is no minimum size criterion for any given rating) in the rating process. Given this, one must adjust for size differences between the proxy group and the target company, even when credit ratings are similar

Q. HAVE YOU PERFORMED STUDIES SPECIFIC TO UTILITY COMPANIES THAT LINK SIZE AND RISK?

A. Yes, I have performed two studies that link size and risk for utility companies. My first study included the universe of electric, gas, and water companies included in *Value Line Standard* and *Small and Mid-Cap Editions*. From each of the utilities' *Value Line Ratings & Reports*, I calculated the 10-year annualized volatility of daily prices (a measure of risk) and current market capitalization (a measure of size) for each company. After ranking the companies by size (largest to smallest) and risk (least risky to most risky), I made a scatter plot of the data, as shown on Chart 1, below:

Chart 1: Relationship Between Size and Risk for the *Value Line* Universe of Utility Companies[57]

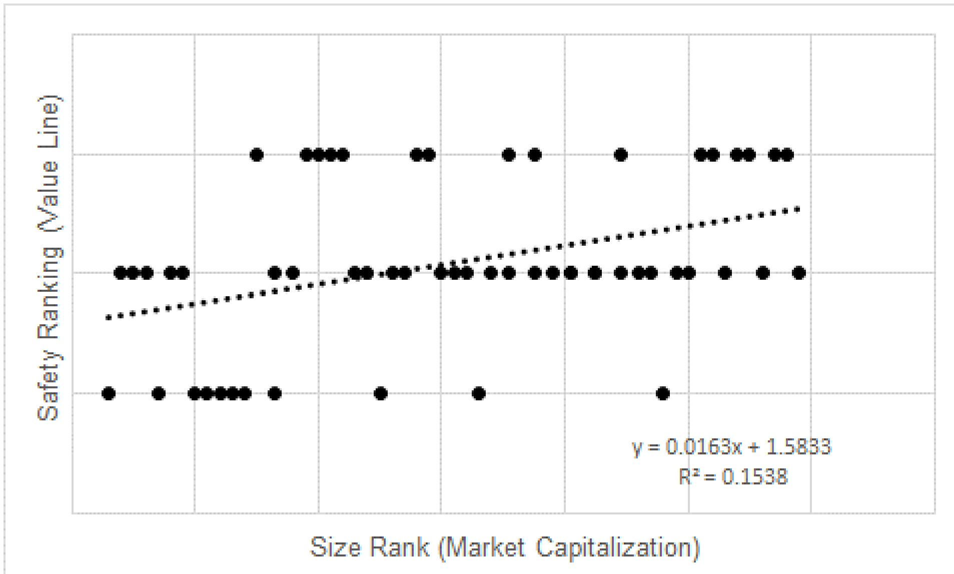


As shown in Chart 1 above, as company size decreases (increasing size rank), the annualized volatility increases, linking size and risk for utilities, which is significant at 95.0% confidence level.

The second study used the same universe of companies, but instead of using annualized volatility, I used the *Value Line* Safety Ranking, which, as discussed previously, is a measure of total risk. After ranking the companies by size and Safety Ranking, I made a scatterplot of those data, as shown on Chart 2, below:

57 Source: *Value Line*

<u>Chart 2: Relationship Between Size and Safety Ranking for the *Value Line* Universe of Utility Companies</u>[58]



Similar to the first study, as company size decreases, Safety Ranking degrades, indicating a link between size and risk for utilities. This study is also significant at the 95% confidence level.

Q. ARE YOU AWARE OF ANOTHER ACADEMIC ARTICLE RELATING TO THE APPLICABILITY OF A SIZE PREMIUM?

A. Yes. An article by Michael A. Paschall, ASA, CFA, and George B. Hawkins ASA, CFA, "Do Smaller Companies Warrant a Higher Discount Rate for Risk?" also supports the applicability of a size premium. As the article makes clear, all else equal, size is a risk factor which must be taken into account when setting the cost of capital or capitalization (discount) rate. Paschall and Hawkins state in their conclusion as follows:

> The current challenge to traditional thinking about a small stock premium is a very real and potentially troublesome issue. The

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[58] Source: *Value Line.*

> challenge comes from bright and articulate people and has already been incorporated into some court cases, providing further ammunition for the IRS. Failing to consider the additional risk associated with most smaller companies, however, is to fail to acknowledge reality. Measured properly, small company stocks have proven to be more risky over a long period of time than have larger company stocks. This makes sense due to the various advantages that larger companies have over smaller companies. Investors looking to purchase a riskier company will require a greater return on investment to compensate for that risk. There are numerous other risks affecting a particular company, yet the use of a size premium is one way to quantify the risk associated with smaller companies.[59]

Hence, Paschall and Hawkins corroborate the need for a small size adjustment, all else equal.

Q. IS THERE A WAY TO QUANTIFY A RELATIVE RISK ADJUSTMENT DUE TO PE'S SMALL SIZE WHEN COMPARED TO THE UTILITY PROXY GROUP?

A. Yes. PE has greater relative risk than the average utility in the Utility Proxy Group because of its smaller size, as measured by an estimated market capitalization of common equity for PE.

[59] *Michael A. Paschall, ASA, CFA and George B. Hawkins ASA, CFA,* Do Smaller Companies Warrant a Higher Discount Rate for Risk?, *CCH Business Valuation Alert, Vol. 1, Issue No. 2, December 1999.*

Table 10: Size as Measured by Market Capitalization for PE's Electric Operations and the Utility Proxy Group

	Market Capitalization* ($ Millions)	Times Greater than The Company
PE	$681.540	
Utility Proxy Group	$22,798.483	33.5x
*From page 1 of Schedule DWD-9.		

PE's estimated market capitalization was $681.5 million as of December 30, 2022, compared with the market capitalization of the average company in the Utility Proxy Group of $22.8 billion as of December 30, 2022. The average company in the Utility Proxy Group has a market capitalization 33.5 times the size of PE's estimated market capitalization.

As a result, it is necessary to upwardly adjust the indicated range of common equity cost rates attributable to the Utility Proxy Group to reflect the Company's greater risk due to their smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2021 period.[60] The average size premium for the Utility Proxy Group with a market capitalization of $22.8 billion falls in the 2nd decile, while the Company's estimated market capitalization of $681.5 million places it in the 8th decile. The size premium spread between the 2nd decile and the 8th decile is 0.78%. Even though a 0.78%

[60] Source: Kroll, Cost of Capital Navigator.

upward size adjustment is indicated, I applied a size premium of 0.15% to the Company's indicated common equity cost rate in order to be conservative.

Q. SINCE PE IS PART OF A LARGER COMPANY, WHY IS THE SIZE OF THE TOTAL COMPANY NOT MORE APPROPRIATE TO USE WHEN DETERMINING THE SIZE ADJUSTMENT?

A. As discussed previously, rates are set using the stand-alone principle, which maintains that the utility operations of a diversified firm should be regulated as though they were independent (*i.e.*, without subsidies to or from affiliated companies). Because of this, the return derived in this proceeding will not apply to FE's operations as a whole, but only PE's. FE is the sum of its constituent parts, including those constituent parts' ROEs. Potential investors in the Parent are aware that it is a combination of operations in each state, and that each state's operations experience the operating risks specific to their jurisdiction. The market's expectation of FE's return is commensurate with the realities of the Company's composite operations in each of the states in which it operates.

B. <u>Credit Risk Adjustment</u>

Q. PLEASE DISCUSS YOUR PROPOSED CREDIT RISK ADJUSTMENT.

A. PE's long-term issuer ratings are Baa2 and BBB from Moody's Investors Services and S&P, respectively, which are slightly more risky than the average long-term issuer ratings for the Utility Proxy Group of Baa1 and BBB+, respectively.[61] Hence, an upward credit risk adjustment is necessary to reflect the lower credit

[61] Source of Information: S&P Global Market Intelligence.

rating, i.e., Baa2, of PE relative to the Baa1 average Moody's bond rating of the Utility Proxy Group.[62]

An indication of the magnitude of the necessary upward adjustment to reflect the greater credit risk inherent in a Baa2 bond rating is one-third of a recent three-month average spread between Moody's A2 and Baa2-rated public utility bond yields of 0.30%, shown on page 4 of Schedule DWD-3, or 0.10%.[63]

Q. DO EXPECTED DEFAULT RATES CHANGE BASED ON A COMPANY'S CREDIT RATING?

A. Yes, they do. Chart 3 below presents Moody's Idealized Cumulative Expected Default Rates for debt obligations with maturities lasting 30-years based on the respective rating.

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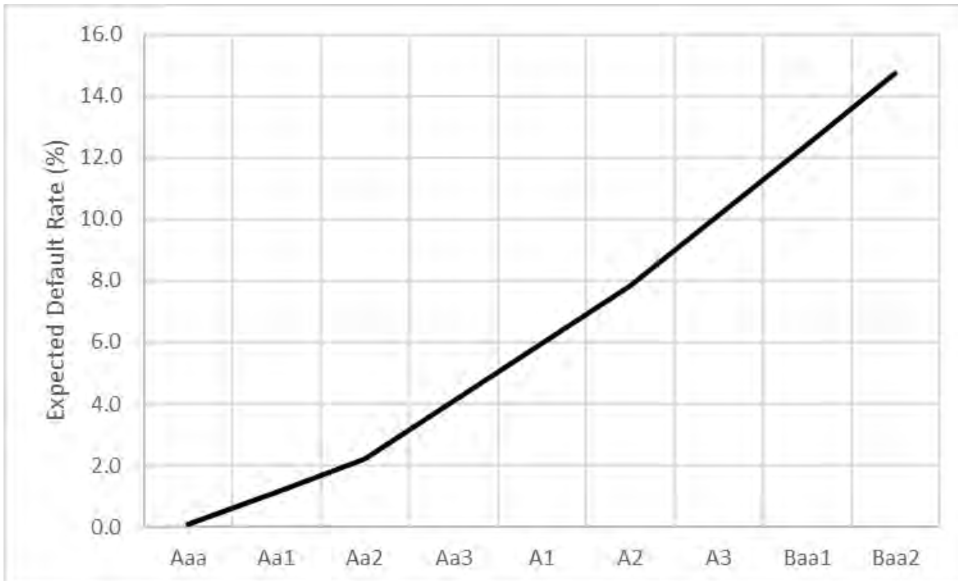
[62] As shown on page 5 of Schedule DWD-3.

[63] 0.10% = 0.30% * (1/3).

Chart 3: Moody's Idealized Cumulative Expected Default Rates Based on Debt Obligations with 30-Year Maturities



As shown in Chart 3, Moody's notes an observable difference in the default rates based on each respective rating. Therefore, even though credit ratings might be similar, the default rates indicate that different ratings equate to different risks, which should be reflected in the Company's authorized ROE.

C. Flotation Cost Adjustment

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance (*e.g.*, underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED COMMON EQUITY COST RATE?

A. It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit recovery of these costs….
>
> The simple fact of the matter is that common equity capital is not free….[Flotation costs] must be recovered through a rate of return adjustment.[64]

Q. SHOULD FLOTATION COSTS BE RECOGNIZED ONLY IF THERE WAS AN ISSUANCE DURING THE TEST YEAR OR THERE IS AN IMMINENT POST-TEST YEAR ISSUANCE OF ADDITIONAL COMMON STOCK?

A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard

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64 Morin, at 329.

regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate, even when there has not been an issuance during the test year, or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be accounted for. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees and the like. For each dollar of issuing market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a company issues stock at $1.00 with 5% in flotation costs, it will net $0.95 in investment. Assuming the investor in that stock requires a 10% return on their invested $1.00 (i.e., a return of $0.10), the company needs to earn approximately 10.5% on its invested $0.95 to receive a $0.10 return.

Q. DO THE COMMON EQUITY COST RATE MODELS YOU HAVE USED ALREADY REFLECT INVESTORS' ANTICIPATION OF FLOTATION COSTS?

A. No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[65] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[66] Consequently, it is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. HOW DID YOU CALCULATE THE FLOTATION COST ALLOWANCE?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing equity that were incurred by FE. Based on the issuance costs shown on page 1 of Schedule DWD-10, an adjustment of 0.19% is required to reflect the flotation costs applicable to the Utility Proxy Group.

Q. DID YOU INCLUDE A 19-BASIS POINT ADJUSTMENT TO YOUR RECOMMENDED RANGE TO REFLECT FLOTATION COSTS?

A. No, I did not. Although I believe a flotation cost adjustment is warranted in this proceeding, I have not reflected it in my recommended range, because I recognize the Commission has typically not made such an adjustment in prior cases. Given that, I believe my recommendation is a conservative estimate of the Company's required return.

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[65] Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson/Southwestern, at p. 342.

[66] Morin, at 342.

Q. WHAT IS THE INDICATED COST OF COMMON EQUITY AFTER YOUR COMPANY-SPECIFIC ADJUSTMENTS?

A. Applying the 0.15% size adjustment and the 0.10% credit risk adjustment to the indicated range of common equity cost rates between 10.05% and 11.05% results in a range of common equity cost rates between 10.29% and 11.29%.

VIII. CONCLUSIONS REGARDING RETURN ON COMMON EQUITY

Q. WHAT IS YOUR RECOMMENDED ROE FOR PE?

A. Given the discussion above and the results from the analyses in this testimony, I recommend that an ROE of 10.60%, within a range between 10.29% and 11.29%, is appropriate for the Company at this time.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.60% FAIR AND REASONABLE TO PE AND ITS CUSTOMERS?

A. Yes, it is.

IX. CREDIT-ADJUSTED RISK-FREE RATE

Q. HAVE YOU CALCULATED A CREDIT-ADJUSTED RISK-FREE RATE FOR PE?

A. Yes, I have.

Q. WHAT IS A CREDIT-ADJUSTED RISK-FREE RATE?

A. A credit-adjusted risk-free rate equates to a risk-free interest rate adjusted for the effect of its credit standing.[67] The credit-adjusted risk-free rate is used solely by

[67] SFAS 143, Paragraph A21.

Maryland as a discount rate in present value calculations for net salvage costs in depreciation studies.

Q. WHY WAS A CREDIT-ADJUSTED RISK-FREE RATE CALCULATED?

A. In the May 26, 2021 Proposed Order of Public Utility Law Judge ("PULJ") in Case No. 9490, the PULJ ruled that a credit-adjusted risk-free rate is the rate that should be used as the discount rate in the SFAS 143 methodology to calculate net salvage costs for the purpose of depreciation accounting (i.e., the "MD Present Value Method"), but there was insufficient evidence as to what a credit-adjusted risk-free rate might be for PE.[68] Although the Company and Company witness Spanos dispute the continued use of the MD Present Value Method, a credit-adjusted risk-free rate has been calculated in the event the MD Present Value Method is ordered by the Commission for the calculation of the Company's net salvage costs for the purposes of depreciation accounting.

Q. HOW DID YOU CALCULATE THE CREDIT-ADJUSTED RISK-FREE RATE?

A. To calculate the credit-adjusted risk-free rate, I started with the three-month average yield on 30-year Treasury bonds as a proxy for the risk-free rate. The average yield on 30-year Treasury bonds is 3.90% for the three months ending December 2022. To reflect the Company's credit standing (Baa2 Moody's bond rating), I applied the three-month average yield spread between 30-year Treasury bonds and Baa2-rated public utility bonds. The average yield spread between 30-

[68] Order at 17.

year Treasury bonds and Baa2-rated utility bonds for the three months ended December 2022 is 2.03%. Applying the credit spread to the three-month average risk-free rate results in a credit-adjusted risk-free rate of 5.93% as shown on Schedule DWD-11.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Resume & Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and has become a leading expert witness with respect to cost of capital and capital structure. He has served as a consultant for investor-owned and municipal utilities and authorities for 14 years. Dylan has testified as an expert witness on over 125 occasions regarding rate of return, cost of service, rate design, and valuation before more than 35 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Regulation and Rates
- Rate of Return
- Valuation
- Mutual Fund Benchmarking
- Capital Market Risk
- Regulatory Strategy
- Cost of Service

Recent Expert Testimony Submission/Appearance

- Regulatory Commission of Alaska – Capital Structure
- Federal Energy Regulatory Commission – Rate of Return
- Public Utility Commission of Texas – Return on Equity
- Hawaii Public Utilities Commission – Cost of Service / Rate Design
- Pennsylvania Public Utility Commission - Valuation

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the City
- Co-authored a valuation report on behalf of a large investor-owned utility company in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Recent Articles and Speeches

- Co-Author of: "Decoupling, Risk Impacts and the Cost of Capital", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal, March, 2020
- Co-Author of: "Decoupling Impact and Public Utility Conservation Investment", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal, 130 (2019), 311-319
- "Establishing Alternative Proxy Groups", before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum, April 4, 2019, New Orleans, LA
- "Past is Prologue: Future Test Year", Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit, May 2, 2017, Savannah, GA.
- Co-author of: "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley, The Electricity Journal, May, 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks", before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	08/22	Atmos Energy Corporation	Docket No. 22AL-0348G	Rate of Return
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Delaware Public Service Commission				
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System	09/20	Peoples Gas System	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure

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Sponsor	Date	Case/Applicant	Docket No.	Subject
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy Corporation	07/19	Atmos Energy Corporation	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy	04/20	Atmos Energy	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy, Inc.	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	Docket No. 15-75	Rate of Return
Minnesota Public Utilities Commission				

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Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Atmos Energy	03/19	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Atmos Energy	07/18	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity

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Sponsor	Date	Case/Applicant	Docket No.	Subject
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
South Dakota Public Service Commission				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return
Tennessee Public Utility Commission				
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Virginia State Corporation Commission				
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
Monongahela Power Company and The Potomac Edison Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
Monongahela Power Company and The Potomac Edison Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

The Potomac Edison Company

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Schedules to the Direct Testimony of Dylan W. D'Ascendis

The Potomac Edison Company
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes
at December 31, 2022

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	46.47%	4.018%	(1)	1.87%
Common Equity	53.53%	10.60%	(2)	5.67%
Total	100.00%			7.54%

Notes:

(1) Company-provided.
(2) From page 2 of this Schedule.

The Potomac Edison Company
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Thirteen Electric Utilities
1.	Discounted Cash Flow Model (DCF) (1)	9.29%
2.	Risk Premium Model (RPM) (2)	11.64%
3.	Capital Asset Pricing Model (CAPM) (3)	11.79%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	12.58%
5.	Indicated Common Equity Cost Rate before Adjustment for Unique Risk	10.04% - 11.04%
6.	Business Risk Adjustment (5)	0.15%
7.	Credit Risk Adjustment (6)	0.10%
8.	Flotation Costs (7)	0.19%
9.	Indicated Common Equity Cost Rate after Adjustment	10.29% - 11.29%
10.	Recommended Common Equity Cost Rate	10.60%

Notes:
(1) From Schedule DWD-2.
(2) From page 1 of Schedule DWD-3.
(3) From page 1 of Schedule DWD-4.
(4) From page 1 of Schedule DWD-8.
(5) Business risk adjustment to reflect The Potomac Edison Company's unique risk compared to the Utility Proxy Group as detailed in the accompanying Direct Testimony.
(6) Company-specific risk adjustment to reflect PE's greater risk due to a lower long-term rating relative to the proxy group as detailed in Mr. D'Ascendis' Direct Testimony.
(7) From page 1 of Schedule DWD-10. Flotation costs not contemplated in range of recommended ROEs.

The Potomac Edison Company
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Thirteen Electric Utilities

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Thirteen Electric Utilities	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
Alliant Energy Corporation	3.20 %	6.00 %	5.90 %	5.53 %	5.81 %	3.29 %	9.10 %
Ameren Corporation	2.81	6.50	6.90	5.91	6.44	2.90	9.34
American Electric Power Corporation	3.64	6.50	6.10	6.18	6.26	3.75	10.01
Duke Energy Corporation	4.19	5.00	5.50	6.15	5.55	4.31	9.86
Edison International	4.80	16.00	2.60	4.40	7.67	4.98	12.65
Entergy Corporation	3.90	4.00	6.80	6.19	5.66	4.01	9.67
Evergy, Inc.	4.08	7.50	5.30	2.43	5.08	4.18	9.26
Eversource Energy	3.22	6.50	6.50	6.42	6.47	3.32	9.79
IDACORP, Inc.	3.05	4.00	3.40	3.40	3.60	3.10	6.70
NorthWestern Corporation	4.61	2.50	1.70	4.50	2.90	4.68	7.58
OGE Energy Corporation	4.37	6.50	5.00	1.90	4.47	4.47	8.94
Portland General Electric Company	3.90	4.50	5.30	1.39	3.73	3.97	7.70
Xcel Energy Inc.	2.93	6.00	6.50	6.80	6.43	3.02	9.45
						Average	9.24 %
						Median	9.34 %
						Average of Mean and Median	9.29 %

Notes:

(1) Indicated dividend at 12/30/2022 divided by the average closing price of the last 60 trading days ending 12/30/2022 for each company.
(2) From pages 2 through 14 of this Schedule.
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 6) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Alliant Energy Corporation, 3.20% x (1+(1/2 x 5.81%)) = 3.29%.
(5) Column 6 + column 7.

Source of Information:

Value Line Investment Survey
www.zacks.com Downloaded on 12/30/2022
www.yahoo.com Downloaded on 12/30/2022
Bloomberg Professional Services

ALLIANT ENERGY NDQ-LNT

RECENT PRICE	55.78	P/E RATIO	20.3 (Trailing: 21.0; Median: 20.0)	RELATIVE P/E RATIO	1.25	DIV'D YLD	3.2%	VALUE LINE

TIMELINESS 4 Lowered 11/18/22
SAFETY 2 Raised 9/28/07
TECHNICAL 4 Lowered 12/9/22
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$45-$80	$63 (10%)

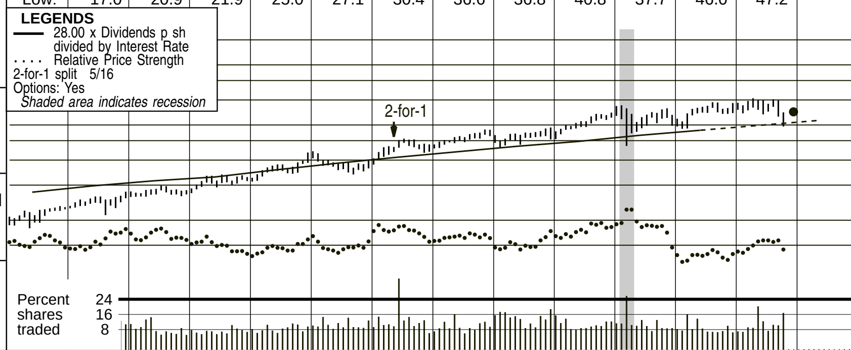
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+25%)	9%
Low	55	(Nil)	3%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	265	314	278
to Sell	259	232	263
Hld's(000)	195423	188290	192005

High:	22.2	23.8	27.1	34.9	35.4	41.0	45.6	46.6	55.4	60.3	62.3	65.4
Low:	17.0	20.9	21.9	25.0	27.1	30.4	36.6	36.8	40.8	37.7	46.0	47.2



Target Price Range
2025 | 2026 | 2027
128 96 80 64 48 40 32 24 16 12

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.0	-13.4
3 yr.	6.0	35.8
5 yr.	38.9	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
14.46	15.57	16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	14.97	14.89	13.67	14.65	**16.35**	**16.90**	Revenues per sh	**18.50**
2.16	2.56	2.28	2.10	2.60	2.75	2.95	3.34	3.49	3.45	3.43	3.97	4.32	4.59	4.92	5.25	**5.50**	**5.75**	"Cash Flow" per sh	**6.75**
1.03	1.35	1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	2.19	2.33	2.47	2.63	**2.70**	**2.95**	Earnings per sh A	**3.50**
.58	.64	.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	1.34	1.42	1.52	1.61	**1.71**	**1.81**	Div'd Decl'd per sh B ■ †	**2.15**
1.71	2.46	3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	6.92	6.69	5.47	4.67	**5.90**	**5.90**	Cap'l Spending per sh	**6.25**
11.42	12.15	12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	19.43	21.24	22.76	23.91	**25.05**	**26.25**	Book Value per sh C	**30.25**
232.25	220.72	220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	236.06	245.02	249.87	250.47	**251.00**	**251.50**	Common Shs Outst'g D	**253.00**
16.8	15.1	13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	19.1	21.2	21.2	21.2	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**18.0**
.91	.80	.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03	1.13	1.09	1.13	*estimates*		Relative P/E Ratio	**1.00**
3.3%	3.1%	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	3.2%	2.9%	2.9%	2.9%			Avg Ann'l Div'd Yield	**3.7%**

CAPITAL STRUCTURE as of 9/30/22
Total Debt $8611 mill. **Due in 5 Yrs** $2126 mill.
LT Debt $7570 mill. **LT Interest** $272 mill.
(LT interest earned: 3.3x)

Leases, Uncapitalized Annual rentals $2 mill.

Pension Assets-12/21 $1011 mill. **Oblig** $1251 mill.

Pfd Stock None

Common Stock 251,021,830 shs.

MARKET CAP: $14.0 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	3534.5	3647.7	3416.0	3669.0	**4100**	**4250**	Revenues ($mill)	**4700**
337.8	382.1	395.7	390.9	384.0	466.1	522.3	567.4	624.0	674.0	**700**	**745**	Net Profit ($mill)	**885**
21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	8.4%	10.8%	10.8%	NMF	**4.0%**	**4.0%**	Income Tax Rate	**4.0%**
6.5%	8.1%	8.8%	9.4%	16.3%	10.7%	14.5%	16.3%	8.8%	3.7%	**4.0%**	**5.0%**	AFUDC % to Net Profit	**6.0%**
48.4%	46.1%	49.7%	47.3%	51.5%	47.8%	52.3%	50.6%	53.5%	52.9%	**54.5%**	**54.0%**	Long-Term Debt Ratio	**55.0%**
48.4%	50.8%	47.5%	50.0%	46.1%	49.8%	45.7%	47.6%	44.9%	47.1%	**45.5%**	**46.0%**	Common Equity Ratio	**45.0%**
6476.6	6461.0	7257.2	7446.3	8377.6	8392.8	10032	10938	12657	12725	**13875**	**14425**	Total Capital ($mill)	**17100**
7838.0	7147.3	6442.0	8970.2	9809.9	10798	12462	13527	14336	14987	**16025**	**17075**	Net Plant ($mill)	**20300**
6.3%	7.0%	6.5%	6.3%	5.6%	6.7%	6.3%	6.3%	5.9%	6.3%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.5%**
10.1%	11.0%	10.8%	10.0%	9.5%	10.6%	10.9%	10.5%	10.6%	11.3%	**11.0%**	**11.5%**	Return on Shr. Equity	**11.5%**
10.3%	11.3%	11.2%	10.2%	9.7%	10.9%	11.2%	10.7%	10.8%	11.0%	**11.0%**	**11.5%**	Return on Com Equity E	**11.5%**
3.9%	4.9%	4.6%	3.6%	2.8%	4.0%	4.4%	4.2%	4.2%	4.3%	**4.5%**	**4.5%**	Retained to Com Eq	**4.5%**
64%	57%	60%	66%	72%	64%	62%	61%	62%	62%	**61%**	**61%**	All Div'ds to Net Prof	**61%**

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	-2.3	+3.7
Avg. Indust. Use (MWH)	11448	11134	NA
Avg. Indust. Revs. per KWH (¢)	6.98	7.55	7.64
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5626	5496	5486
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.6	+.8
Fixed Charge Cov. (%)	265	251	259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-.5%	*4.5%*
"Cash Flow"	7.0%	7.5%	*5.5%*
Earnings	7.0%	8.0%	*6.0%*
Dividends	6.5%	6.5%	*6.0%*
Book Value	5.5%	7.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	987.2	790.2	990.2	880.1	3647.7
2020	916	763	920	817	3416.0
2021	901	817	1024	927	3669.0
2022	1068	943	1135	***954***	***4100***
2023	***1100***	***925***	***1175***	***1050***	***4250***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.53	.40	.94	.46	2.33
2020	.72	.54	.94	.26	2.47
2021	.68	.57	1.02	.35	2.63
2022	.77	.63	.90	***.40***	***2.70***
2023	***.80***	***.65***	***1.05***	***.45***	***2.95***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.335	.335	.335	.335	1.34
2019	.355	.355	.355	.355	1.42
2020	.38	.38	.38	.38	1.52
2021	.4025	.4025	.4025	.4025	1.61
2022	.4275	.4275	.4275	.4275	

BUSINESS: Alliant Energy Corporation (formerly Interstate Energy) is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity to 985,000 customers and gas to 425,000 customers in Wisconsin, Iowa, and Minnesota. Electric revenue by state: WI, 43%; IA, 56%. MN, 1%. Electric revenue: residential, 36%; commercial, 25%; industrial, 29%; wholesale, 8%; other, 2%. Generating sources: coal, 32%; gas, 32%; wind, 16%; other, 1%; purchased, 19%. Fuel costs: 25% of revs. '21 reported deprec. rates: 2.9%-6.1%. Has 3,300 employees. Chairman, President & CEO: John O. Larsen. Inc.: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718-2148. Tel.: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy came up a bit short in the September quarter. Indeed, on a reported basis, the Wisconsin-based electric utility earned $0.90 a share in the period, down 12% year over year, even as overall revenue rose 11%, to nearly $1.14 billion. Weighing on EPS was, among other things, a one-time charge below the operating line (included in our estimates). Notably, Alliant wrote down the value of tax assets on its balance sheet after Iowa's Department of Revenue announced a reduction in state levies on corporate income beginning next year. That said, operating conditions remained generally favorable, with warmer-than-normal weather driving increased air-conditioner and electricity use across Alliant's three-state footprint.

The utility's investment roadmap includes a notable amount of energy storage. In late September, Alliant filed a plan with the Public Service Commission of Wisconsin, calling for the addition of 175 megawatts of battery storage in the state. Specifically, the facilities would be located in Grant and Wood counties, alongside two previously-approved solar arrays. Importantly, they'd provide bridge power for more than 180,000 homes at times when sun- and wind-power generation is inadequate.

The Inflation Reduction Act (IRA) that was signed into law in mid-August is expected to be a big benefit. As we understand it, new financing options under the IRA will enable Alliant Energy to take full ownership of 12 solar-power farms that it currently shares with several investment partners. According to a recent report, the transition could save the utility and its customers upwards of $138 million.

Shares of Alliant Energy are ranked 4 (Below Average) for relative year-ahead price performance. At the recent quotation, we think that buy-and-hold investors will also do better elsewhere. Notably, at 3.2%, the dividend yield is below both the utility average and less-risky returns offered by United States Treasuries. Prospects over the next 18 months and the 3- to 5-year period are also subpar. Like many electric utility issues, the recent quotation is within our 2025-2027 Target Price Range.

Nils C. Van Liew *December 9, 2022*

(A) Diluted EPS. Excl. nonrecurring losses: '11, 1¢; '12, 8¢. '20 & '21 EPS don't sum due to rounding. Next earnings report due late Feb. (B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '21: $1,980 mill., $7.91/sh. (D) In millions, adj. for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '20: various; in WI in '22: 10%; earned on avg. com. eq., '21: 11.3%. Regulatory Climate: Wisconsin, Above Average; Iowa, Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	95

AMEREN NYSE-AEE

RECENT PRICE **87.94** | P/E RATIO **20.8** (Trailing: 22.0 Median: 19.0) | RELATIVE P/E RATIO **1.28** | DIV'D YLD **2.8%** | VALUE LINE

TIMELINESS **4** Lowered 12/2/22
SAFETY **1** Raised 9/10/21
TECHNICAL **4** Lowered 12/9/22
BETA .85 (1.00 = Market)

High:	34.1	35.3	37.3	48.1	46.8	54.1	64.9	70.9	80.9	87.7	90.8	99.2
Low:	25.5	28.4	30.6	35.2	37.3	41.5	51.4	51.9	63.1	58.7	69.8	73.3

LEGENDS
— 35.70 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

18-Month Target Price Range
Low-High: $81-$129 | Midpoint (% to Mid): $105 (20%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+15%)	6%
Low	80	(-10%)	1%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	294	305	287
to Sell	262	257	274
Hld's(000)	200507	201631	204282

Percent shares traded 30 20 10

Target Price Range 2025 | 2026 | 2027

160 120 100 80 60 50 40 30 20 15

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.8	-13.4
3 yr.	12.7	35.8
5 yr.	49.5	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	25.73	24.00	22.87	24.81	*27.25*	*28.10*	Revenues per sh	*30.00*
6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	7.64	7.83	8.08	8.89	*9.50*	*10.05*	"Cash Flow" per sh	*11.75*
2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	3.32	3.35	3.50	3.84	*4.10*	*4.35*	Earnings per sh A	*5.25*
2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	1.85	1.92	2.00	2.20	*2.36*	*2.52*	Div'd Decl'd per sh B ■	*3.10*
4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	9.56	9.92	13.02	13.67	*12.90*	*12.55*	Cap'l Spending per sh	*13.00*
31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	31.21	32.73	35.29	37.64	*40.20*	*42.90*	Book Value per sh C	*51.25*
206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	244.50	246.20	253.30	257.70	*262.50*	*267.00*	Common Shs Outst'g D	*280.00*
19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	18.3	22.1	22.2	21.4	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	1.14	1.14	*Value Line*		Relative P/E Ratio	*.95*
4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	3.0%	2.6%	2.6%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $14798 mill. **Due in 5 Yrs** $3446 mill.
LT Debt $13577 mill. **LT Interest** $436 mill.
(LT interest earned: 3.8x)
Pension Assets-12/21 $5745 mill. **Oblig** $5457 mill.
Pfd Stock $129 mill. **Pfd Div'd** $5 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 487,508 sh. 4.00% to 5.16%, $100 par, redeem. $100-$104.30/sh.
Common Stock 258,522,169 shs.
as of 10/31/22
MARKET CAP: $23 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	6291.0	5910.0	5794.0	6394.0	*7150*	*7500*	Revenues ($mill)	*8400*
589.0	518.0	593.0	585.0	659.0	683.0	821.0	834.0	877.0	995.0	*1075*	*1165*	Net Profit ($mill)	*1455*
36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	22.4%	17.9%	15.0%	13.6%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
6.1%	7.1%	5.7%	5.1%	4.1%	5.6%	6.9%	5.8%	5.5%	6.0%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	50.3%	52.1%	55.0%	56.1%	*55.5%*	*53.5%*	Long-Term Debt Ratio	*51.0%*
49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	44.3%	43.3%	*44.0%*	*46.0%*	Common Equity Ratio	*48.5%*
13384	12190	12975	13968	13840	14420	15632	17116	20158	22391	*23900*	*24950*	Total Capital ($mill)	*29500*
16096	16205	17424	18799	20113	21466	22810	24376	26807	29261	*31225*	*33050*	Net Plant ($mill)	*38400*
6.0%	5.6%	5.8%	5.3%	6.0%	6.0%	6.4%	6.0%	5.3%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	10.6%	10.2%	9.7%	10.1%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	9.7%	10.2%	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	4.8%	4.4%	4.2%	4.4%	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
66%	76%	67%	70%	64%	64%	56%	57%	57%	57%	*58%*	*58%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.5	-5.6	+2.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	307	291	325

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	*4.0%*
"Cash Flow"	3.0%	6.0%	*6.0%*
Earnings	3.0%	7.5%	*6.5%*
Dividends	3.0%	4.0%	*7.0%*
Book Value	1.0%	4.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1556	1379	1659	1316	5910
2020	1440	1398	1628	1328	5794
2021	1566	1472	1811	1545	6394
2022	1879	1726	2306	*1239*	*7150*
2023	*1900*	*1700*	*2100*	*1800*	*7500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.78	.72	1.47	.38	3.35
2020	.59	.98	1.47	.46	3.50
2021	.91	.80	1.65	.48	3.84
2022	.97	.80	1.74	*.59*	*4.10*
2023	*1.00*	*.90*	*1.80*	*.65*	*4.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.4575	.4575	.4575	.475	1.85
2019	.475	.475	.475	.495	1.92
2020	.495	.495	.495	.515	2.00
2021	.55	.55	.55	.55	2.20
2022	.59	.59	.59	.59	

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric revenue breakdown: residential, 49%; commercial, 34%; industrial, 8%; other, 9%. Generating sources: coal, 73%; nuclear, 11%; hydro & other, 9%; purchased, 7%. Fuel costs: 25% of revenues. '21 reported deprec. rates: 3%-4%. Has 9,100 employees. Chairman: Warner L. Baxter. President & CEO: Martin J. Lyons, Jr. Inc.: Missouri. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren reported in-line results for the September quarter. Earnings per share of $1.74 were a penny higher than our estimate and 5% greater than the year-ago tally. Earnings at Ameren Missouri, the largest segment, benefited from higher electric service rates. This was partially offset by higher operations and maintenance expenses derived from unfavorable market returns and company-owned life insurance investments. Earnings at the three remaining business segments were solid, primarily due to increased investments in infrastructure.

The company's guidance has improved a bit. Due to strong execution, management narrowed the 2022 earnings guidance to a range of $4.00 to $4.15 per share. This compares to the initial guidance range of $3.95 to $4.15 per share. Importantly, the year-to-date benefits it has seen from weather and higher-than-expected 30-year Treasury rates are mostly being offset by the aforementioned company-owned life insurance investment performance, as well as higher than expected short-term and long-term borrowing rates. The current five-year plan includes a 6% to 8% compounded annual growth rate for earnings from 2022 through 2026. This should be driven primarily by strong rate base growth and infrastructure investment. It expects dividend growth to be in line with long-term earnings growth and is planning for a payout ratio range of 55% to 70%.

Business investment is paying off. At Ameren Missouri, the company estimates that over 6.5 million minutes of customer outages have been avoided in 2022 due to recent infrastructure investments. Meanwhile, the Inflation Reduction Act (IRA) was enacted in August, and is designed to help reduce the cost of the clean energy transition. It provides tax credits for wind, solar, and nuclear energy centers, as well as energy storage, carbon capture utilization and hydrogen development. The incentives in the IRA align well with the companywide goal of reaching net zero carbon emissions by 2045.

The dividend yield of this high-quality stock is below the utility mean. The recent price is within our 2025-2027 Target Price Range.

Kevin Downing *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. gain (losses): '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from discontinued ops.: '13, (92¢); '15, 21¢. Next earnings report due mid-Feb.
(B) Div'ds paid late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '21: $6.60/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate allowed on com. eq. in MO in '22: elec. & gas, none specified; in IL: electric, varies; in '21: gas, 9.67%; earned on avg. com. eq., '21: 10.6%. Regulatory Climate: MO, Average; IL, Below Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	95

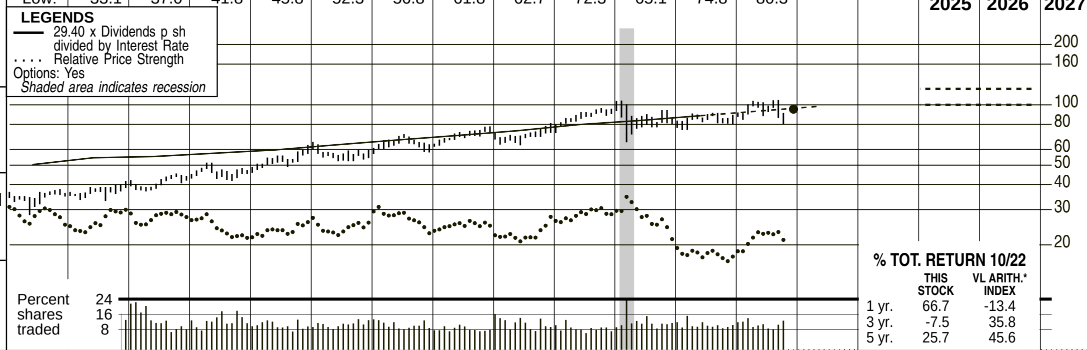
AMERICAN ELEC. PWR. NDQ-AEP

RECENT PRICE **95.22** | P/E RATIO **18.6** (Trailing: 19.7 Median: 17.0) | RELATIVE P/E RATIO **1.14** | DIV'D YLD **3.5%** | VALUE LINE

TIMELINESS 3 Raised 4/1/22
SAFETY 1 Raised 3/17/17
TECHNICAL 2 Lowered 11/18/22
BETA .75 (1.00 = Market)

High:	41.7	45.4	51.6	63.2	65.4	71.3	78.1	81.1	96.2	105.0	91.5	105.6	
Low:	33.1	37.0	41.8	45.8	52.3	56.8	61.8	62.7	72.3	65.1	74.8	80.3	

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$89-$127 $108 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+25%)	9%
Low	100	(+5%)	5%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	673	634	624
to Sell	475	521	499
Hld's(000)	382433	385400	384675

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	66.7	-13.4
3 yr.	-7.5	35.8
5 yr.	25.7	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	32.84	31.49	30.04	33.30	*35.20*	*35.95*	Revenues per sh	*38.55*
6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	8.77	9.35	10.28	10.98	*11.50*	*11.95*	"Cash Flow" per sh	*14.00*
2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	3.90	4.08	4.42	4.96	*5.00*	*5.35*	Earnings per sh A	*6.50*
1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	2.53	2.71	2.84	3.00	*3.17*	*3.35*	Div'd Decl'd per sh B ■ †	*4.00*
8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	12.89	12.43	12.72	11.43	*15.35*	*14.15*	Cap'l Spending per sh	*14.00*
23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	38.58	39.73	41.38	44.49	*47.30*	*50.30*	Book Value per sh C	*59.00*
396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	494.17	496.60	504.21	*514.00*	*523.00*	Common Shs Outst'g D	*545.00*
12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	18.0	21.4	19.6	17.1	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	1.01	.93	*Value Line*		Relative P/E Ratio	*.95*
4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	3.6%	3.1%	3.3%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $36349 mill. **Due in 5 Yrs** $12886 mill.
LT Debt $33647 mill. **LT Interest** $1067 mill.
Incl. $549.4 mill. securitized bonds. Incl. $500.7 mill. finance leases.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $119.6 mill.
Pension Assets-12/21 $5352.9 mill. **Oblig** $5187.0 mill.
Pfd Stock None

Common Stock 513,863,678 shs. as of 10/27/22
MARKET CAP: $48.9 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
14945	15357	17020	16453	16380	15425	16196	15561	14919	16792	*18100*	*18800*	Revenues ($mill)	*21000*
1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	2200.1	2488.1	*2580*	*2775*	Net Profit ($mill)	*3565*
33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	5.8%	.7%	1.9%	4.6%	*7.0%*	*7.0%*	Income Tax Rate	*7.0%*
11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	10.7%	12.7%	9.7%	7.8%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*5.0%*
50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	58.5%	58.3%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*57.5%*
49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	*42.0%*	*42.0%*	Common Equity Ratio	*42.5%*
30823	32913	33001	35633	34775	37707	40677	44759	49537	53734	*57775*	*62950*	Total Capital ($mill)	*75900*
38763	40997	44117	46133	45639	50262	55099	60138	63902	66001	*70650*	*74600*	Net Plant ($mill)	*87300*
6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	5.6%	5.6%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.5%*
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	*11.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	*11.0%*	*10.5%*	Return on Com Equity E	*11.0%*
3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	3.8%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
63%	62%	61%	60%	54%	67%	65%	67%	65%	61%	*63%*	*63%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	- -	+3.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+1.0	NA
Fixed Charge Cov. (%)	234	243	272

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-1.5%	*3.5%*
"Cash Flow"	4.5%	5.0%	*5.5%*
Earnings	4.5%	4.0%	*6.5%*
Dividends	5.0%	6.0%	*6.0%*
Book Value	4.0%	3.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	4056	3573	4315	3616	15561
2020	3747	3494	4066	3610	14918
2021	4281	3826	4623	4061	16792
2022	4593	4640	5526	*3341*	*18100*
2023	*4800*	*4300*	*5150*	*4550*	*18800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.16	.93	1.48	.51	4.08
2020	1.00	1.05	1.50	.87	4.42
2021	1.15	1.15	1.59	1.07	4.96
2022	1.41	1.02	1.33	*1.24*	*5.00*
2023	*1.30*	*1.25*	*1.75*	*1.05*	*5.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.62	.62	.62	.67	2.53
2019	.67	.67	.67	.70	2.71
2020	.70	.70	.70	.74	2.84
2021	.74	.74	.74	.78	3.00
2022	.78	.78	.78	.83	

BUSINESS: American Electric Power Company Inc. (AEP), through 10 operating utilities, serves 5.5 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 43%; commercial, 23%; industrial, 18%; wholesale, 10%; other, 6%. Sold commercial barge operation in '15. Generating sources not available. Fuel costs: 33% of revenues. '21 reported depreciation rates (utility): 2.6%-12.5%. Has 16,700 employees. Chairman, President & CEO: Nicholas K. Akins. COO: Lisa Barton. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power will soon complete a divestiture, and the company is interested in shedding other assets. AEP expects to raise $1.45 billion from the sale of its Kentucky Power subsidiary. The motivation for the sale is the entity's lack of an adequate return on equity. The last remaining hurdle before the deal can go through is the approval of an application, which should be received by mid December. The transaction would then close by early January. The company has also started accepting initial bids for its 1,600-megawatt portfolio of nonregulated renewable-energy projects, either piecemeal or as a whole. Management is now moving on to the due diligence process with select bidders. It expects the process to close in the June quarter of 2023. Meanwhile, the company is conducting a strategic review of the retail business which it expects to complete in the first half of 2023. Following divestitures, AEP plans to expand its investments in regulated renewable-energy projects, which have less risk than nonutility assets, and electric transmission.

The company appears well positioned to meet or exceed its full-year guidance. American continues to realize above-forecast, weather-normalized load (the amount of electricity on the grid at any given time), which is now 2.6% above pre-pandemic levels. Year to date, residential, commercial, and industrial sales comparisons are up .3%, 3.8%, and 5.5%, respectively. This compares to the company's 2.9% (revised upward from 1.6%) retail sales forecast for 2022. The company should continue to benefit from rate relief, increased investment in its transmission business, and volume growth. Our $5.00 GAAP earnings estimate is within management's guidance (on a GAAP basis) of $4.97-$5.07 a share. At the analyst day in early October, the company established its 2023 earnings per share guidance range at $5.19-$5.39 and the long-term bottom line growth rate at 6%-7%.

The dividend yield of this top-quality stock is at the utility average. Total return potential is unspectacular for the next 18 months and Timeliness is average. Further, the recent quotation is just below our 2025-2027 Target Price Range.

Kevin Downing *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; '19, (20¢); gains (loss) from disc. ops.: '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). Next earnings report due late Jan. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '21: $17.04/sh. (D) In mill. (E) Rate base: various. Rates allowed on com. eq.: 9.3%-10.9%; earned on avg. com. eq., '21: 11.6%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

DUKE ENERGY NYSE-DUK

RECENT PRICE **93.18** | P/E RATIO **17.1** (Trailing: 17.7 / Median: 18.0) | RELATIVE P/E RATIO **1.11** | DIV'D YLD **4.3%** | **VALUE LINE**

TIMELINESS	3 Raised 5/20/22
SAFETY	2 New 6/1/07
TECHNICAL	2 Lowered 11/4/22
BETA	.85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$88-$134	$111 (20%)

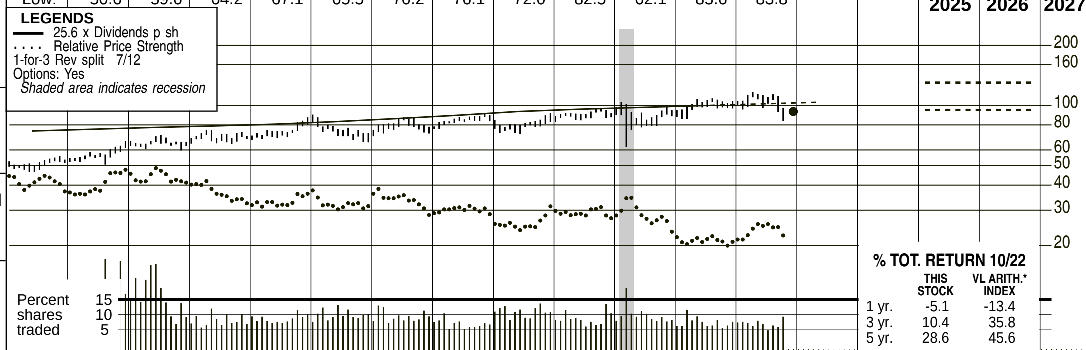
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+40%)	12%
Low	95	(Nil)	5%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	934	942	877
to Sell	627	651	688
Hld's(000)	484677	487269	491735

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	66.4	71.1	75.5	87.3	90.0	87.8	91.8	91.4	97.4	103.8	108.4	116.3
Low:	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.0	82.5	62.1	85.6	83.8



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.1	-13.4
3 yr.	10.4	35.8
5 yr.	28.6	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	34.21	31.04	32.64	35.05	36.05	Revenues per sh	37.90
7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	11.05	12.12	12.04	12.60	13.25	14.00	"Cash Flow" per sh	16.00
2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.72	5.06	5.12	5.24	5.45	5.75	Earnings per sh A	6.50
- -	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	3.75	3.82	3.90	3.98	4.06	Div'd Decl'd per sh B ■	4.30
8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	15.17	12.88	12.63	16.00	16.75	Cap'l Spending per sh	16.75
62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	61.20	59.82	61.55	62.75	64.50	Book Value per sh C	70.00
418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	727.00	733.00	769.00	769.00	770.00	770.00	Common Shs Outst'g D	770.00
- -	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	17.0	17.7	17.1	18.9	Bold figures are		Avg Ann'l P/E Ratio	17.0
- -	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	.92	.94	.88	1.02	Value Line		Relative P/E Ratio	.95
- -	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%	4.2%	4.4%	3.9%	estimates		Avg Ann'l Div'd Yield	3.9%

CAPITAL STRUCTURE as of 6/30/22
Total Debt $70193 mill. **Due in 5 Yrs** $19536 mill.
LT Debt $63147 mill. **LT Interest** $2206 mill.
Incl. $915 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $225 mill.
Pension Assets-12/21 $9235 mill. **Oblig** $8207 mill.
Pfd Stock $1962 mill. **Pfd Div'd** $107 mill.
40 mill. shs. 5.75%, cum., $25 liq. value, redeemable at $25.50 prior to 6/15/24; 1 mill. shs. 4.875%, cum., $1000 liq. value.
Common Stock 769,968,724 shs. **as of 7/31/22**
MARKET CAP: $84.6 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
19624	24598	23925	23459	22743	23565	24521	25079	23868	25097	27000	27750	Revenues ($mill)	29200
2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	3339.0	3747.0	3878.0	4133.0	4200	4500	Net Profit ($mill)	5040
30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	14.1%	12.7%	.3%	5.1%	10.0%	9.0%	Income Tax Rate	9.0%
22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	11.4%	8.0%	6.9%	5.9%	8.0%	7.0%	AFUDC % to Net Profit	7.0%
47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	53.8%	54.0%	53.7%	55.1%	56.5%	58.5%	Long-Term Debt Ratio	61.0%
52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	44.4%	43.1%	42.0%	40.0%	Common Equity Ratio	37.5%
77307	79482	78088	77222	86609	90774	94940	101807	103589	109744	115150	124525	Total Capital ($mill)	144100
68558	69490	70046	75709	82520	86391	91694	102127	106782	111408	117725	124375	Net Plant ($mill)	141100
3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	4.6%	4.7%	4.8%	4.8%	4.5%	4.5%	Return on Total Cap'l	4.5%
5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	7.6%	8.0%	8.1%	8.4%	8.5%	9.0%	Return on Shr. Equity	9.0%
5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	7.6%	8.3%	8.2%	8.5%	8.5%	9.0%	Return on Com Equity E	9.0%
.9%	1.5%	1.7%	1.5%	.6%	1.2%	2.0%	2.4%	2.3%	1.9%	2.5%	2.5%	Retained to Com Eq	3.0%
82%	78%	76%	79%	91%	83%	74%	71%	73%	78%	76%	73%	All Div'ds to Net Prof	68%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.9	-2.3	+2.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	233	183	209

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-.5%	2.5%
"Cash Flow"	4.0%	5.0%	5.0%
Earnings	3.0%	4.5%	5.0%
Dividends	3.0%	3.5%	2.0%
Book Value	2.0%	1.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	6163	5873	6940	6103	25079
2020	5949	5421	6721	5777	23868
2021	6150	5758	6951	6238	25097
2022	7132	6685	7255	5928	27000
2023	7250	6750	7375	6375	27750

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.24	1.12	1.79	.91	5.06
2020	1.14	1.08	1.87	1.03	5.12
2021	1.26	1.15	1.88	.94	5.24
2022	1.30	1.14	1.86	1.15	5.45
2023	1.30	1.20	2.00	1.10	5.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.9275	.9275	3.64
2019	.9275	.9275	.945	.945	3.75
2020	.945	.945	.965	.965	3.82
2021	.965	.965	.985	.985	3.90
2022	.985	.985	1.005		

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, & KY, and 1.6 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 45%; commercial, 28%; industrial, 13%; other, 14%. Generating sources: gas, 32%; nuclear, 30%; coal, 18%; other, 1%; purchased, 19%. Fuel costs: 28% of revs. '21 reported deprec. rate: 2.9%. Has 27,600 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

Duke Energy has a number of rate cases pending. In North Carolina, Duke Energy Progress requested a boost of $326 million (8.5%) in 2023, $151 million (3.9%) in 2024, and $138 million (3.6%) in 2025. In South Carolina, Duke Energy Progress proposed its first base rate case in four years, and expects rates to go into effect in early 2023. In Ohio, the utility is seeking a $55 million (3%) hike, as the rate case hearing nears a conclusion. Adjusted second-quarter earnings of $1.14 a share, slightly outperformed our call of $1.10. Our 2022 full-year estimate remains at $5.45 a share. Management reaffirmed a range of $5.30 to $5.60, and a long-term earnings growth rate of 5% to 7% through 2026. Rate relief and strong retail volumes were the main drivers to the bottom line in the second period. Volume growth increased 2.6% year over year, which is higher than 2019 levels.

We look for a strong earnings performance in 2023, near the company's growth target of between 5% and 7%. Higher electric volumes should continue, and Duke Energy raised its load growth prediction to 1.5%-2% from 1.5%. The utility is estimating cost mitigation of $200 million starting in 2023, due to rising interest rates and inflation.

The company is very focused on carbon reduction and the development of clean and renewable energy projects. Currently, the utility has 5,000 megawatts of Commericial wind, solar, and battery projects, ranking it within the top-10 largest renewable companies in the United States. By 2035, the company intends to reach 30,000 megawatts of renewable energy. Duke plans to invest $145 billion over the next 10 years and achieve net-zero carbon emissions by 2050 in its clean energy transition. Management expects carbon emission reduction to exceed 50% by 2030, and 80% by 2040.

The stock has dropped 20% in value since our August report, alongside losses by most of its peers over that time due to rising interest rates. Despite the stock's price reduction, its 18-month and 3- to 5-year capital appreciation potential does not stand out. Meanwhile, this issue is ranked 3 (Average) for Timeliness.

Zachary J. Hodgkinson November 11, 2022

(A) Dil. EPS. Excl. net nonrec. losses: '12, 64¢; '13, 22¢; '14, 59¢; '15, 5¢; '16, 60¢; '18, 96; '20, $3.40; '21, 30¢; 1Q22, 22¢; net nonrec gain: '17, 14¢. 2021 EPS don't sum to annual due to rounding. Next egs. due early Feb. **(B)** Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '21: $41.34/sh. **(D)** In mill., adj. for rev. split. **(E)** Rate base: Net orig. cost. Rate all'd on com. eq. in '21 in NC: 9.6%; in '19 in SC: 9.5%; in '20 in FL: 9.5%-11.5%; in '20 in IN: 9.7%. Reg. Clim.: NC, SC Avg.; OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	100

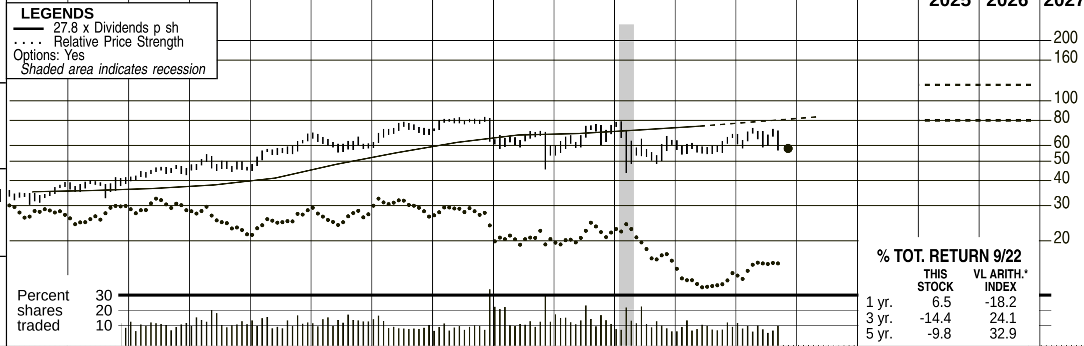
EDISON INTERNAT'L NYSE-EIX

RECENT PRICE 57.85 | P/E RATIO 12.8 (Trailing: 23.2, Median: 17.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 4 Lowered 9/23/22
SAFETY 3 Lowered 11/23/18
TECHNICAL 2 Raised 9/23/22
BETA .95 (1.00 = Market)

High:	41.6	48.0	54.2	68.7	69.6	78.7	83.4	71.0	76.4	78.9	68.6	73.3
Low:	32.6	39.6	44.3	44.7	55.2	58.0	62.7	45.5	53.4	43.6	53.9	56.6

LEGENDS
—— 27.8 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$57-$95	$76 (30%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+105%)	23%
Low	80	(+40%)	12%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	356	323	368
to Sell	252	291	254
Hld's(000)	335565	332086	333217

% TOT. RETURN 9/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.5	-18.2
3 yr.	-14.4	24.1
5 yr.	-9.8	32.9

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	38.85	34.11	35.83	39.18	**42.65**	**43.35**	Revenues per sh	**47.45**
7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	4.69	9.15	7.94	8.58	**11.05**	**11.65**	"Cash Flow" per sh	**13.55**
3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	d1.26	3.98	1.72	2.00	**4.50**	**4.85**	Earnings per sh A	**6.25**
1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	2.43	2.48	2.58	2.69	**2.84**	**3.00**	Div'd Decl'd per sh B ■	**3.55**
7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	13.84	13.47	14.47	14.47	**14.90**	**15.20**	Cap'l Spending per sh	**16.65**
23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	35.82	32.10	36.75	37.08	36.57	**37.30**	**39.55**	Book Value per sh C	**47.85**
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	361.99	378.91	380.38	**382.00**	**382.00**	Common Shs Outst'g D	**390.00**
13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	- -	16.7	34.9	29.7	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	.87	- -	.89	1.79	1.63	*Value Line*		Relative P/E Ratio	**.90**
2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%	3.8%	3.7%	4.3%	4.5%	*estimates*		Avg Ann'l Div'd Yield	**3.6%**

CAPITAL STRUCTURE as of 6/30/22
Total Debt $27318 mill. **Due in 5 Yrs** $9600 mill.
LT Debt $25143 mill. **LT Interest** $990 mill.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $623 mill.
Pension Assets-12/21 $4296 mill.
Oblig $4171 mill.
Pfd Stock $3878 mill. **Pfd Div'd** $211 mill.
350,000 sh. 6.25%, $1000 liq. value; 638,020 sh. 5.0%-5.75%, $2500 liq. value; 1,250,000 sh. 5.375%, 750,000 sh. 5%, $1000 liq. value, all cum.
Common Stock 381,431,985 shs.
as of 7/29/22
MARKET CAP: $22.1 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
11862	12581	13413	11524	11869	12320	12657	12347	13578	14905	**16300**	**16550**	Revenues ($mill)	**18500**
1594.0	1344.0	1539.0	1480.0	1422.0	1603.0	d290.0	1477.0	775.0	925.0	**1720**	**1855**	Net Profit ($mill)	**2440**
14.3%	25.2%	22.4%	6.6%	11.1%	5.0%	- -	- -	- -	- -	**5.0%**	**5.0%**	Income Tax Rate	**5.0%**
8.5%	7.8%	5.8%	8.0%	6.8%	7.2%	- -	11.1%	22.5%	18.5%	**10.0%**	**9.0%**	AFUDC % to Net Profit	**7.0%**
45.2%	45.7%	44.1%	45.0%	41.8%	45.6%	53.6%	53.5%	55.2%	57.6%	**57.5%**	**58.5%**	Long-Term Debt Ratio	**61.5%**
46.2%	46.2%	47.2%	46.7%	49.2%	45.8%	38.3%	39.9%	39.5%	33.2%	**32.0%**	**32.0%**	Common Equity Ratio	**32.0%**
20422	21516	23216	24352	24362	25506	27284	33360	35581	41959	**44500**	**47000**	Total Capital ($mill)	**60500**
30273	30455	32981	35085	37000	39050	41348	44285	47839	50700	**53900**	**57500**	Net Plant ($mill)	**66750**
8.9%	7.3%	7.7%	7.1%	6.9%	7.3%	.1%	5.6%	3.4%	3.3%	**6.0%**	**5.5%**	Return on Total Cap'l	**5.5%**
14.2%	11.5%	11.9%	11.1%	10.0%	11.6%	NMF	9.5%	4.9%	5.2%	**11.5%**	**11.0%**	Return on Shr. Equity	**11.5%**
15.9%	12.5%	13.0%	12.0%	10.8%	12.7%	NMF	10.2%	4.6%	5.5%	**13.0%**	**13.0%**	Return on Com Equity E	**13.0%**
11.4%	8.1%	8.8%	7.2%	5.6%	6.6%	NMF	4.1%	NMF	NMF	**6.5%**	**5.5%**	Retained to Com Eq	**6.0%**
32%	40%	37%	44%	53%	52%	NMF	63%	NMF	125%	**63%**	**62%**	All Div'ds to Net Prof	**57%**

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.7	+.7	-3.9
Avg. Indust. Use (MWH)	657	589	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22009	23133	21190
Annual Load Factor (%)	49.6	46.7	52.7
% Change Customers (yr-end)	+.5	+.6	+.3
Fixed Charge Cov. (%)	172	NMF	113

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	-.5%	4.5%
"Cash Flow"	- -	-3.5%	8.0%
Earnings	-2.5%	-9.0%	16.0%
Dividends	7.5%	8.5%	5.5%
Book Value	1.5%	1.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2824	2812	3741	2970	12347
2020	2790	2987	4644	3157	13578
2021	2960	3315	5299	3331	14905
2022	3968	4008	**5000**	**3324**	**16300**
2023	**3425**	**3725**	**5675**	**3725**	**16550**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.64	1.57	1.35	.45	3.98
2020	.50	.85	d.76	1.13	1.72
2021	.68	.84	d.90	1.38	2.00
2022	1.07	.94	**1.65**	**.84**	**4.50**
2023	**1.10**	**1.00**	**1.70**	**1.05**	**4.85**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.605	.605	.605	.605	2.42
2019	.6125	.6125	.6125	.6125	2.45
2020	.6375	.6375	.6375	.6375	2.55
2021	.6625	.6625	.6625	.6625	2.65
2022	.70	.70	.70		

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.2 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 43%; commercial, 45%; industrial, 3%; other, 9%. Generating sources: nuclear, 8%; gas, 3%; hydro, 3%; purch., 86%. Power costs: 37% of revs. '21 reported depr. rate: 3.7%. Has 13,000 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Edison International's earnings are set for a sharp rise in 2022. In 2018, wildfires and mudslides wreaked havoc on the company's bottom line. The claims tied to these disasters then landed on the books in 2020 and 2021. For 2022, we expect a much cleaner ledger, which should result in core share net climbing to the $4.50 level. Looking ahead to next year, we look for something in line with the in-house goal of 5% to 7% earnings growth, so we are reiterating our $4.85 target. Of course, there are potential hurdles to such gains, most notably the California Public Utilities Commission (CPUC). This entity could potentially trim Edison's 2022 ROE from 10.3% to 9.72% retroactively, but at this time we still do not think this will happen, given the current market conditions. Once this proceeding is completed, additional regulatory decisions will be made on 2023 through 2025. The rulings of the CPUC will have a noticeable impact on year-over-year earnings, and for now we view the regulatory climate here as average, so we are not factoring in any shakeups in the ROE path.

Doing business in California is expensive, and the electricity industry is particularly cost heavy. The state's size and geography inflate fixed operating costs. More specifically, generation, maintenance, distribution, wildfire-related expenditures, and public programs are all costly. EIX bears some of this burden, while a good chunk is passed onto residents. The average Californian pays 28% more annually for their electric than the national average.

Investments by Edison in wildfire risk mitigation will continue. In the last three and a half years, 3,500 circuit miles of bare wire were replaced with covered conductor, and in the next couple of years a 1,200 mile pace is expected. With that, capital spending and long-term debt should head higher in the coming years.

This utility's dividend yield is a full percentage point above the industry's average. The payout is running higher as investor fears about California heightened during a September heat wave. Elsewhere, this untimely selection also has slightly below average readings for the 18-month window and for the pull to 2025-2027.

Erik M. Manning *October 21, 2022*

(A) Dil. EPS. Excl. nonrec. gains (losses): '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); '18, (15¢); '19, (21¢); '20, 25¢; gains (loss) from disc. ops.: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. '19 EPS don't sum due to change in shs. Next earnings report due early November. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '21: $20.14/sh. (D) In mill. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '20: 10.3%; earned on avg. com. eq., '21: 5.4%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	75
Price Growth Persistence	35
Earnings Predictability	10

ENTERGY CORP. NYSE-ETR

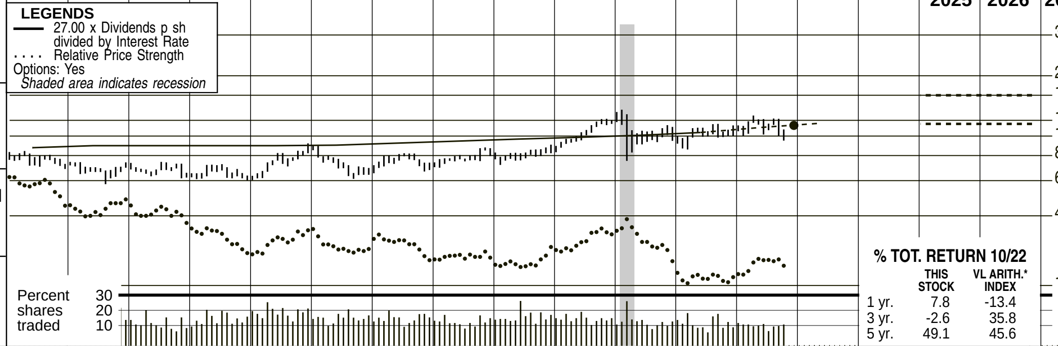
RECENT PRICE	113.25	P/E RATIO	17.0 (Trailing: 18.1; Median: 14.0)	RELATIVE P/E RATIO	1.04	DIV'D YLD	3.8%	VALUE LINE

TIMELINESS	3	Raised 9/2/22
SAFETY	2	Raised 12/13/19
TECHNICAL	4	Lowered 12/9/22
BETA .95 (1.00 = Market)		

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	74.5	74.5	72.6	92.0	90.3	82.1	87.9	90.8	122.1	135.5	115.0	126.8	
Low:	57.6	61.6	60.2	60.4	61.3	65.4	69.6	71.9	83.2	75.2	85.8	94.9	

Target Price Range 2025 | 2026 | 2027

LEGENDS
— 27.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$99-$158	$129 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+40%)	*12%*
Low	115	(Nil)	*5%*

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	327	348	348
to Sell	281	260	258
Hld's(000)	179128	184330	184841

Percent shares traded 30 20 10

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.8	-13.4
3 yr.	-2.6	35.8
5 yr.	49.1	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
53.94	59.47	69.15	56.82	64.27	63.67	57.94	63.86	69.71	64.54	60.55	61.35	58.23	54.63	50.51	57.95	*63.10*	*56.45*	Revenues per sh	*61.50*
10.69	11.73	12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	18.72	16.70	16.50	17.19	18.21	17.90	*17.75*	*17.95*	"Cash Flow" per sh	*20.50*
5.36	5.60	6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.81	6.88	5.19	5.88	6.30	6.90	6.87	*6.65*	*6.80*	Earnings per sh A	*8.50*
2.16	2.58	3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.34	3.42	3.50	3.58	3.66	3.74	3.86	*4.10*	*4.30*	Div'd Decl'd per sh B ■ †	*5.10*
9.44	10.29	13.92	12.99	13.33	15.21	18.18	15.73	14.82	16.79	17.28	22.07	22.45	21.72	24.52	30.86	*18.15*	*19.00*	Cap'l Spending per sh	*19.75*
40.45	40.71	42.07	45.54	47.53	50.81	51.73	54.00	55.83	51.89	45.12	44.28	46.78	51.34	54.56	57.42	*60.00*	*63.55*	Book Value per sh C	*74.00*
202.67	193.12	189.36	189.12	178.75	176.36	177.81	178.37	179.24	178.39	179.13	180.52	189.06	199.15	200.24	202.65	*206.00*	*209.00*	Common Shs Outst'g D	*214.00*
14.3	19.3	16.6	12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	15.0	13.8	16.5	15.3	15.0	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.77	1.02	1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75	.75	.88	.79	.80	*Value Line*		Relative P/E Ratio	*.90*
2.8%	2.4%	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	4.5%	4.4%	3.5%	3.6%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $27606 mill. **Due in 5 Yrs** $11117 mill.
LT Debt $24635 mill. **LT Interest** $824.0 mill.
Incl. $54.7 mill. of securitization bonds.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $65.3 mill.
Pension Assets-12/21 $6993.1 mill.
Oblig $8409.6 mill.
Pfd Stock $254.4 mill. **Pfd Div'd** $18.3 mill.
200,000 shs. 6.25%-7.5%, $100 par; 250,000 shs. 8.75%, 1.4 mill. shs. 5.375%; all cum., without sinking fund.
Common Stock 203,483,660 shs. **as of 10/31/22**
MARKET CAP: $23.0 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
10302	11391	12495	11513	10846	11074	11009	10879	10114	11743	*13000*	*11800*	Revenues ($mill)	*13150*
1091.9	904.5	1060.0	1061.2	1249.8	950.7	1092.1	1258.2	1406.7	1402.8	*1370*	*1420*	Net Profit ($mill)	*1845*
13.0%	26.7%	37.8%	2.2%	11.3%	1.8%	NMF	NMF	NMF	16.1%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
11.9%	10.1%	9.3%	7.4%	8.1%	14.7%	17.5%	16.7%	12.2%	7.1%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*7.0%*
55.8%	55.1%	54.9%	57.8%	63.6%	63.6%	63.2%	62.0%	65.5%	67.6%	*66.5%*	*66.5%*	Long-Term Debt Ratio	*66.0%*
42.9%	43.6%	43.8%	40.8%	35.5%	35.5%	35.9%	37.1%	33.7%	31.7%	*32.5%*	*33.0%*	Common Equity Ratio	*33.5%*
21432	22109	22842	22714	22777	22528	24602	27557	32386	36733	*38050*	*40200*	Total Capital ($mill)	*47300*
27299	27882	28723	27824	27921	29664	31974	35183	38853	42244	*43750*	*45425*	Net Plant ($mill)	*50800*
6.4%	5.4%	6.0%	6.0%	6.9%	5.7%	5.8%	5.9%	5.6%	4.8%	*3.0%*	*4.5%*	Return on Total Cap'l	*5.0%*
11.5%	9.1%	10.3%	11.1%	15.1%	11.6%	12.0%	12.0%	12.6%	11.6%	*9.5%*	*10.5%*	Return on Shr. Equity	*11.5%*
11.6%	9.2%	10.4%	11.2%	15.2%	11.7%	12.2%	12.1%	12.7%	11.9%	*9.5%*	*10.5%*	Return on Com Equity E	*11.5%*
5.2%	3.0%	4.4%	4.8%	7.7%	3.9%	4.9%	5.2%	5.9%	5.2%	*3.5%*	*4.0%*	Retained to Com Eq	*4.5%*
56%	68%	58%	58%	50%	68%	61%	58%	55%	57%	*62%*	*64%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.4	-4.1	+3.2
Avg. Indust. Use (MWH)	1070	1017	1015
Avg. Indust. Revs. per KWH(¢)	5.24	4.95	5.91
Capacity at Peak (Mw)	23887	25665	NA
Peak Load, Summer (Mw)	21598	21340	NA
Annual Load Factor (%)	64	62	NA
% Change Customers (yr-end)	+.8	+1.0	+1.0
Fixed Charge Cov. (%)	165	202	243

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-3.5%	*2.0%*
"Cash Flow"	1.0%	-.5%	*2.5%*
Earnings	- -	1.5%	*4.0%*
Dividends	1.5%	2.0%	*5.0%*
Book Value	1.5%	1.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2610	2666	3141	2462	10879
2020	2427	2413	2904	2370	10114
2021	2845	2822	3353	2723	11743
2022	2878	3395	4219	*2508*	*13000*
2023	*2950*	*2850*	*3250*	*2750*	*11800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.32	1.22	1.82	1.94	6.30
2020	.59	1.79	2.59	1.93	6.90
2021	1.66	1.30	2.63	1.28	6.87
2022	1.36	1.78	2.84	*.67*	*6.65*
2023	*1.40*	*1.75*	*2.90*	*.75*	*6.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.89	.91	3.58
2019	.91	.91	.91	.93	3.66
2020	.93	.93	.93	.95	3.74
2021	.95	.95	.95	1.01	3.86
2022	1.01	1.01	1.01	1.07	

BUSINESS: Entergy Corporation supplies electricity to 3 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 206,000 customers in Louisiana. Is selling its last nonutility nuclear unit (shut down 5/22). Electric revenue breakdown: residential, 37%; commercial, 24%; industrial, 27%; other, 12%. Generating sources: gas, 46%; nuclear, 30%; coal, 6%; purchased, 18%. Fuel costs: 32% of revenues. '21 reported depreciation rate: 2.7%. Has 12,400 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy Corp. recorded solid third-quarter results. Revenues expanded to $4.2 billion, aided by strong growth across its electric services business and higher energy prices. Positives included healthy demand from industrial companies, while population growth across the southern United States was positive. The company also benefited from several rate cases being approved, allowing for more recoveries, and a few projects were placed into service. Still, costs rose at a quick rate, especially those related to fuel costs, while operational maintenance was much higher. Overall, adjusted earnings rose to $2.84 per share during the quarter. The fourth-quarter performance will likely be lackluster as the company faces tough comparisons from 2021, which had cooler-than-usual weather. It exited some non-regulated nuclear operations in Michigan over the past year, and it sold some shares to fund capital expenditures. We estimate adjusted earnings will reach $0.67 per share in the final quarter of 2022.

The long-term outlook is decent. Entergy should gain from population and industrial growth across its coverage area. Additionally, it has filed for several rate cases, including for Entergy New Orleans and Entergy Texas, with a decision on the latter due in the second quarter of 2023. Additionally, the company has been investing in renewable energy projects that will come online in the years ahead, helping to bolster revenues, and regulators could approve more. Costs for fuel and maintenance will likely increase with the added operations. The company has been funding capital expenditures with debt and equity sales, which should limit profit-per-share gains. Bad-debt expenses may well pick up if the economy slows further. We project adjusted earnings per share of $6.80 in 2023 and $8.50 in 2025-2027.

The board raised the quarterly dividend by 6% to $1.07. This payout remains well covered by profits and should expand steadily in the years ahead.

Shares of Entergy Corp. are neutrally ranked for Timeliness. This stock has a good dividend yield and long-term upside potential is subpar. Overall, we think this is best suited for conservative income-seeking accounts.

John E. Seibert III *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. losses: '12, $1.26; '13, $1.14; '14, 56¢; '15, $6.99; '16, $10.14; '17, $2.91; '18, $1.25; '21, $1.33; '22, $1.19. Next earnings report due early Feb. **(B)** Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. **(C)** Incl. deferred charges. In '21: $35.95/sh. **(D)** In mill. **(E)** Rate base: Net original cost. Allowed ROE (blended): 9.95%; earned on avg. com. eq., '21: 12.1%. Regulatory Climate: Average.

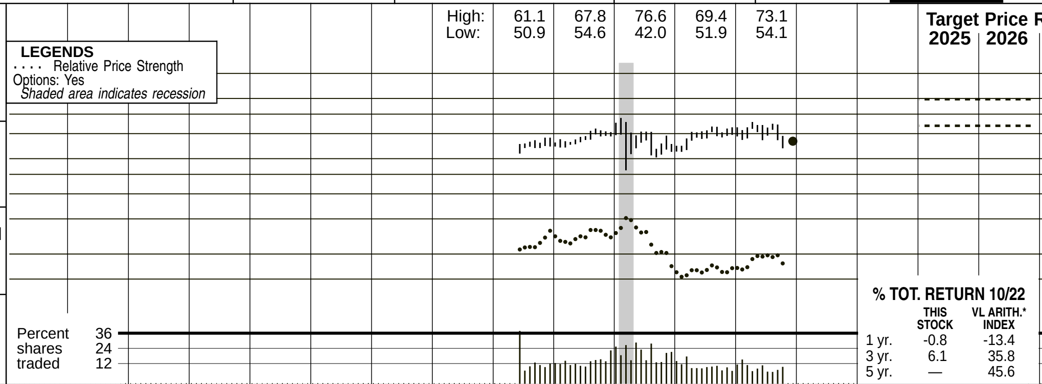
Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	70

EVERGY, INC. NYSE-EVRG

RECENT PRICE 58.69 | P/E RATIO 16.4 (Trailing: 17.0 Median: NMF) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 9/2/22
SAFETY 2 New 9/14/18
TECHNICAL 3 Lowered 11/18/22
BETA .90 (1.00 = Market)

	2018	2019	2020	2021	2022
High:	61.1	67.8	76.6	69.4	73.1
Low:	50.9	54.6	42.0	51.9	54.1



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$53-$88	$71 (20%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+60%)	16%
Low	70	(+20%)	8%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	284	304	305
to Sell	270	252	250
Hld's(000)	196288	194242	193700

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.8	-13.4
3 yr.	6.1	35.8
5 yr.	—	45.6

Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Great Plains Energy holders received .5981 of a share of Evergy for each of their shares, and Westar Energy holders received one share of Evergy for each of their shares. The merger was completed on June 4, 2018. Shares of Evergy began trading on the New York Stock Exchange one day later.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
- -	- -	- -	- -	- -	- -	16.75	22.71	21.66	24.36	24.80	25.20	Revenues per sh	26.50
- -	- -	- -	- -	- -	- -	4.89	7.18	7.06	8.18	8.05	8.40	"Cash Flow" per sh	10.00
- -	- -	- -	- -	- -	- -	2.50	2.79	2.72	3.83	3.55	3.75	Earnings per sh A	4.75
- -	- -	- -	- -	- -	- -	1.74	1.93	2.05	2.18	2.33	2.48	Div'd Decl'd per sh B ■	3.05
- -	- -	- -	- -	- -	- -	4.19	5.34	6.88	8.60	8.60	9.20	Cap'l Spending per sh	9.50
- -	- -	- -	- -	- -	- -	39.28	37.82	38.50	40.32	41.40	42.70	Book Value per sh C	47.50
- -	- -	- -	- -	- -	- -	255.33	226.64	226.84	229.30	230.00	230.00	Common Shs Outst'g D	230.00
- -	- -	- -	- -	- -	- -	22.7	21.8	21.7	16.2	Bold figures are		Avg Ann'l P/E Ratio	17.5
- -	- -	- -	- -	- -	- -	1.23	1.16	1.11	.87	Value Line		Relative P/E Ratio	.95
- -	- -	- -	- -	- -	- -	3.1%	3.2%	3.5%	3.5%	estimates		Avg Ann'l Div'd Yield	3.7%
- -	- -	- -	- -	- -	- -	4275.9	5147.8	4913.4	5586.7	5700	5800	Revenues ($mill)	6100
- -	- -	- -	- -	- -	- -	535.8	669.9	618.3	879.7	835	880	Net Profit ($mill)	1115
- -	- -	- -	- -	- -	- -	9.8%	12.6%	14.1%	11.7%	9.0%	9.0%	Income Tax Rate	9.0%
- -	- -	- -	- -	- -	- -	2.5%	2.5%	5.5%	5.0%	5.0%	6.0%	AFUDC % to Net Profit	5.0%
- -	- -	- -	- -	- -	- -	40.0%	50.6%	51.3%	50.1%	51.5%	51.5%	Long-Term Debt Ratio	53.5%
- -	- -	- -	- -	- -	- -	60.0%	49.4%	48.7%	49.9%	48.5%	48.5%	Common Equity Ratio	46.5%
- -	- -	- -	- -	- -	- -	16716	17337	17924	18542	19675	20175	Total Capital ($mill)	23400
- -	- -	- -	- -	- -	- -	18952	19346	20106	21150	22100	23150	Net Plant ($mill)	26300
- -	- -	- -	- -	- -	- -	4.0%	4.8%	4.5%	5.7%	5.0%	5.5%	Return on Total Cap'l	6.0%
- -	- -	- -	- -	- -	- -	5.3%	7.8%	7.1%	9.5%	8.5%	9.0%	Return on Shr. Equity	10.0%
- -	- -	- -	- -	- -	- -	5.3%	7.8%	7.1%	9.5%	8.5%	9.0%	Return on Com Equity E	10.0%
- -	- -	- -	- -	- -	- -	.6%	2.4%	1.8%	4.1%	3.0%	3.0%	Retained to Com Eq	3.5%
- -	- -	- -	- -	- -	- -	89%	69%	75%	57%	64%	65%	All Div'ds to Net Prof	63%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $11664 mill. **Due in 5 Yrs** $4388.2 mill.
LT Debt $9197.2 mill. **LT Interest** $305.5 mill.
Incl. $40.9 mill. finance leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $18.8 mill.

Pension Assets-12/21 $1714.7 mill. **Oblig** $2561.7 mill.

Pfd Stock None

Common Stock 229,536,385 shs. **as of 10/31/22**
MARKET CAP: $13.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	NA	-3.9	+3.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.25	7.14	6.94
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	305	286	350

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	- -	- -	2.5%
"Cash Flow"	- -	- -	5.0%
Earnings	- -	- -	7.5%
Dividends	- -	- -	7.0%
Book Value	- -	- -	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1217	1222	1578	1131	5148
2020	1117	1185	1517	1094	4913
2021	1612	1236	1617	1122	5587
2022	1224	1447	1909	1120	5700
2023	1225	1450	1900	1225	5800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.39	.57	1.56	.28	2.79
2020	.31	.59	1.60	.22	2.72
2021	.84	.81	1.95	.23	3.83
2022	.53	.84	1.86	.32	3.55
2023	.60	.80	2.05	.30	3.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.40	.40	.46	.475	1.74
2019	.475	.475	.475	.505	1.93
2020	.505	.505	.505	.535	2.05
2021	.535	.535	.535	.5725	2.18
2022	.5725	.5725	.6125		

BUSINESS: Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Through its subsidiaries (now doing business under the Evergy name), provides electric service to 1.6 million customers in Kansas and Missouri, including the greater Kansas City area. Electric revenue breakdown: residential, 34%; commercial, 30%; industrial, 11%; wholesale, 13%; other, 12%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 28% of revenues. '21 reported deprec. rate: 3%. Has 4,900 employees. Chairman: Mark A. Ruelle. President & CEO: David A. Campbell. COO: Kevin E. Bryant. Inc.: Missouri. Address: 1200 Main Street, Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.evergy.com.

Evergy delivered strong financial results in the third quarter. Earnings of $1.86 a share, on revenues of $1.9 billion, both exceeded Wall Street's expectations and increased 75%, and 27% from the last period, respectively. The performance was due primarily to the company's improved transmission margin, along with continued favorable demand in all sectors. Total demand has grown 3% this year and 2.4% in the September-period, driven by increases in industrial demand such as the chemical and oil and gas sectors.

The company raised its 2022 earnings range from $3.43-$3.63 a share to $3.53-$3.63 due to the better-than-expected September-period showing. Management remains committed to its long-term EPS growth-rate target of 6%-8% annualy. We have adjusted our top-line estimate which now stands at $5.7 billion, up from our previous call of $5.4 billion. In 2023, we are forecasting revenues of $5.8 billion and earnings of $3.75 per share.

Evergy has hiked its dividend by 7%. The dividend yield of 4.2%, which is solid for a utility should appeal to income-oriented investors. Management is targeting a dividend growth rate in line with earnings at a 60%-70% payout.

The company hopes to get approval on its acquisition of the Permisson Creek Wind Farm by year end. The $250 million investment will boost the renewable energy business and assist the utility in its goal of net-zero carbon emissions by 2045.

Evergy shares have underperformed of late. The stock has declined more than 16% in value over the past three months, alongside losses by many of its peers. The utility industry has struggled recently due to the challenging interest-rate environment. Higher yields on Treasuries have prompted a growing number of income-oriented investors to enter the bond market, and the competition has not augured well for utilities. Due to its recent price struggles, capital appreciation potential over the 18-month span, and 3- to 5-year period have improved since our last review. Also, these shares are ranked to mirror the broader market averages over the next year. But the dividend continues to be the main attraction here.

Zachary J. Hodgkinson December 9, 2022

(A) Diluted earnings. '19 EPS don't sum to full-year total due to rounding. Next earnings report due late February. (B) Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '21: $4,327.7 mill., $18.87/sh. (D) In millions. (E) Rate base: Original cost depreciated. Rate allowed on common equity in Missouri in '18: none specified; in Kansas in '18: 9.3%; earned on average common equity, '21: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	35
Earnings Predictability	NMF

EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 76.28 | P/E RATIO 18.1 (Trailing: 18.7 Median: 19.0) | RELATIVE P/E RATIO 1.18 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 8/19/22
SAFETY 1 Raised 5/22/15
TECHNICAL 2 Lowered 11/4/22
BETA .90 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$78-$129 $104 (35%)

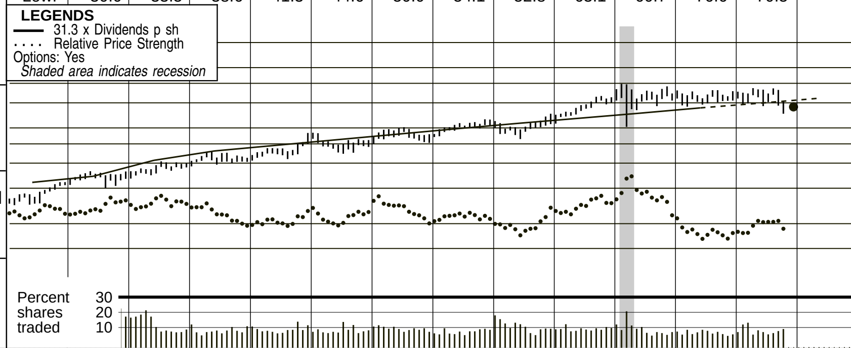
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+50%)	14%
Low	95	(+25%)	9%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	366	412	411
to Sell	312	315	308
Hld's(000)	275552	269412	271816

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	36.5	40.9	45.7	56.7	56.8	60.4	66.1	70.5	86.6	99.4	92.7	94.6
Low:	30.0	33.5	38.6	41.3	44.6	50.0	54.1	52.8	63.1	60.7	76.6	70.5



Target Price Range
2025 | 2026 | 2027
160
120
100
80
60
50
40
30
20
15

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.5	-13.4
3 yr.	-0.9	35.8
5 yr.	40.9	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	25.08	24.11	24.46	26.66	25.85	25.96	28.64	**32.75**	**34.20**	Revenues per sh	**37.00**
3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	4.94	5.46	5.84	6.64	6.65	6.99	7.74	**8.10**	**8.55**	"Cash Flow" per sh	**10.00**
.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	2.76	2.96	3.11	3.25	3.45	3.64	3.86	**4.10**	**4.40**	Earnings per sh A	**5.30**
.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	1.67	1.78	1.90	2.02	2.14	2.27	2.41	**2.55**	**2.70**	Div'd Decl'd per sh B ■	**3.30**
5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	5.44	6.24	7.41	7.96	8.83	8.58	9.22	**11.20**	**10.50**	Cap'l Spending per sh	**9.50**
18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	32.64	33.80	34.99	36.25	38.29	41.01	42.39	**44.20**	**46.50**	Book Value per sh C	**53.75**
154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	317.19	316.89	316.89	316.89	329.88	342.95	344.40	**348.00**	**351.00**	Common Shs Outst'g D	**365.00**
27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	18.1	18.7	19.5	18.7	22.1	23.7	22.2	*Bold figures are*		Avg Ann'l P/E Ratio	**19.5**
1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.91	.98	.98	1.01	1.18	1.22	1.19	*Value Line*		Relative P/E Ratio	**1.10**
3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	3.3%	3.2%	3.1%	3.3%	2.8%	2.6%	2.8%	*estimates*		Avg Ann'l Div'd Yield	**3.2%**

CAPITAL STRUCTURE as of 6/30/22
Total Debt $21423 mill. **Due in 5 Yrs** $8313.5 mill.
LT Debt $20016 mill. **LT Interest** $619.8 mill.
(Total Interest coverage: 3.9x)

Leases, Uncapitalized Annual rentals $11.1 mill.

Pension Assets-12/21 $6495.5 mill.
Oblig $6729.7 mill.
Pfd Stock $155.6 mill. **Pfd Div'd** $7.6 mill.

Common Stock 346,443,316 shs.
as of 7/31/22
MARKET CAP: $26.4 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
6273.8	7301.2	7741.9	7954.8	7639.1	7752.0	8448.2	8526.5	8904.4	9863.1	**11400**	**12000**	Revenues ($mill)	**13500**
533.0	793.7	827.1	886.0	949.8	995.5	1040.5	1121.0	1244.8	1337.7	**1430**	**1545**	Net Profit ($mill)	**1935**
34.0%	35.0%	36.2%	37.9%	36.9%	36.8%	21.7%	19.7%	22.2%	21.9%	**24.0%**	**24.0%**	Income Tax Rate	**24.0%**
2.3%	1.4%	2.4%	2.9%	3.9%	4.7%	6.1%	6.3%	5.3%	4.2%	**5.0%**	**4.0%**	AFUDC % to Net Profit	**3.0%**
43.7%	44.3%	45.9%	45.6%	44.8%	51.2%	52.4%	52.8%	52.4%	54.2%	**54.5%**	**55.0%**	Long-Term Debt Ratio	**56.0%**
55.4%	54.8%	53.2%	53.6%	54.4%	48.2%	46.9%	46.6%	47.1%	45.3%	**45.0%**	**44.5%**	Common Equity Ratio	**44.0%**
16675	17544	18738	19313	19697	23018	24474	27097	29842	32233	**34325**	**36650**	Total Capital ($mill)	**44700**
16605	17576	18647	19892	21351	23617	25610	27585	30883	33378	**36025**	**38400**	Net Plant ($mill)	**44500**
4.2%	5.5%	5.3%	5.5%	5.8%	5.2%	5.2%	5.1%	5.1%	5.1%	**5.0%**	**5.0%**	Return on Total Cap'l	**5.5%**
5.7%	8.1%	8.2%	8.4%	8.7%	8.9%	8.9%	8.8%	8.8%	9.1%	**9.0%**	**9.5%**	Return on Shr. Equity	**10.0%**
5.7%	8.2%	8.2%	8.5%	8.8%	8.9%	9.0%	8.8%	8.8%	9.1%	**9.0%**	**9.5%**	Return on Com Equity E	**10.0%**
1.6%	3.4%	3.5%	3.4%	3.5%	3.5%	3.4%	3.6%	3.5%	3.6%	**3.5%**	**3.5%**	Retained to Com Eq	**3.5%**
72%	59%	58%	61%	60%	61%	62%	60%	60%	61%	**62%**	**62%**	All Div'ds to Net Prof	**62%**

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.3	-2.7	+1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.8	+.6
Fixed Charge Cov. (%)	319	345	324

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	2.0%	5.5%
"Cash Flow"	3.5%	7.5%	6.0%
Earnings	6.0%	5.5%	6.5%
Dividends	8.5%	6.5%	6.5%
Book Value	6.5%	4.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2416	1884	2176	2050	8526.5
2020	2373	1953	2344	2234	8904.4
2021	2826	2122	2433	2482	9863.1
2022	3471	2573	**2750**	**2606**	**11400**
2023	**3650**	**2700**	**2900**	**2750**	**12000**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.97	.74	.98	.76	3.45
2020	1.02	.76	1.01	.85	3.64
2021	1.15	.79	1.02	.91	3.86
2022	1.30	.86	**1.03**	**.91**	**4.10**
2023	**1.35**	**.92**	**1.11**	**1.02**	**4.40**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.505	.505	.505	.505	2.02
2019	.535	.535	.535	.535	2.14
2020	.5675	.5675	.5675	.5675	2.27
2021	.6025	.6025	.6025	.6025	2.41
2022	.6375	.6375	.6375		

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities with 3.3 mill. electric, 887,000 gas, 226,000 water customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to 3/4 of New Hampshire's population; supplies power to western Massachusetts and parts of eastern MA & gas to central & eastern MA; supplies water to CT, MA, & NH. Acq'd NSTAR 4/12; Aquarion 12/17; Columbia Gas 10/20. Electric rev. breakdown: residential, 53%; commercial, 33%; industrial, 5%; other, 9%. Fuel costs: 34% of revs. '21 reported depr. rate: 3.1%. Has 9,200 empls. Chairman: James J. Judge. Pres. & CEO: Joseph R. Nolan, Jr. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy is on pace for a solid year. The company is receiving a full year's effect from last November's natural gas price hike in Massachusetts, with the rate set to rise again this November. Eversource is also benefiting from transmission and distribution (T&D) capital projects, which raise the rate base (property, plant, and equipment on which utilities are allowed to earn an economic rate of return). The rising rate base increases the company's electric rates annually through a forward-looking algorithm that takes regulatory lag out of the equation for T&D investments. We expect earnings will be up about 6.5% this year to $4.10 per share. (Note: Eversource is due to report third-quarter financial results shortly after this report goes to press.)

We look for more of the same going forward. NSTAR has a pending electric rate case in Massachusetts, with a decision due in December. The utility requested increases of $46 million and $47 million at the start of 2023 and 2024, respectively, based on a 10.5% return on equity (50 basis points higher than the rate of return granted in 2018). This may be a bit of a stretch. Nevertheless, we think a constructive outcome is likely and rates should increase in January.

Leadership has adjusted its clean-energy strategy. Eversource is shopping its stake in non-regulated offshore wind ventures, deeming them outside of its risk tolerance and too high a drain on capital. Instead, the company plans to benefit from this new power source's growth in New England through the relative safety of regulated T&D projects, such as those necessary to connect wind generation to the grid. Modernization programs that ready its territories for the electrification of the transportation system will also serve to grow its rate base. Regulated renewable-power-generation ventures will likely remain a viable option, as well.

Total returns for this issue over the 18-month time frame look attractive. We view Eversource as a desirable holding for utility investors due to its superior earnings and dividend growth rates relative to its peer group. Its yield is 30 basis points below the industry average, but we think the valuation premium is justified.

Anthony J. Glennon *November 11, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '08, (19¢); '10, 9¢; '19, (64¢); '20, (9¢); '21, (32¢); 1Q-2Q '22, (3¢). Next earnings report due early Feb. **(B)** Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. deferred charges. In '21: $9064 mill., $26.32/sh. **(D)** In mill. **(E)** Rate allowed on com. eq. in MA: (elec.) '18, 10.0%; (gas) '20, 9.7%-9.9%; in CT: (elec.) '18, 9.25%; (gas) '18, 9.3%; in NH: '21, 9.3%; Regulatory Climate: CT, Below Average; NH, Average; MA, Above Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	100

IDACORP, INC. NYSE-IDA

RECENT PRICE 96.53 | P/E RATIO 19.2 (Trailing: 20.3, Median: 19.0) | RELATIVE P/E RATIO 1.31 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 4 Lowered 9/23/22
SAFETY 1 Raised 1/22/21
TECHNICAL 2 Raised 10/14/22
BETA .80 (1.00 = Market)

High:	42.7	45.7	54.7	70.1	70.5	83.4	100.0	102.4	114.0	113.6	113.8	118.9
Low:	33.9	38.2	43.1	50.2	55.4	65.0	77.5	79.6	89.3	69.1	85.3	95.8

18-Month Target Price Range
Low-High: $94-$148 | Midpoint (% to Mid): $121 (25%)

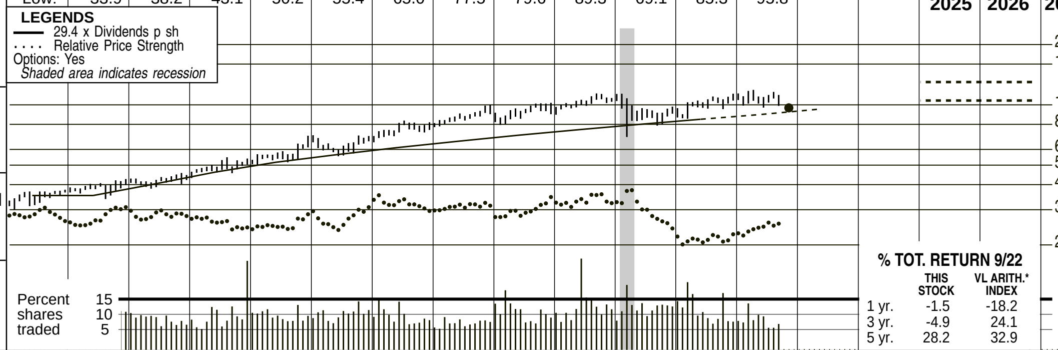
Target Price Range 2025 | 2026 | 2027

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+35%)	10%
Low	105	(+10%)	5%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	208	181	174
to Sell	137	164	164
Hld's(000)	39410	39894	40518



% TOT. RETURN 9/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.5	-18.2
3 yr.	-4.9	24.1
5 yr.	28.2	32.9

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	27.19	26.70	26.77	28.86	**28.40**	**28.65**	Revenues per sh	**34.25**
4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	7.85	8.07	8.19	8.41	**8.30**	**8.85**	"Cash Flow" per sh	**10.40**
2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	4.49	4.61	4.69	4.85	**5.00**	**5.25**	Earnings per sh A	**6.00**
1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	2.40	2.56	2.72	2.88	**3.05**	**3.25**	Div'd Decl'd per sh B ■ †	**4.00**
5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	5.51	5.53	6.16	5.94	**10.15**	**14.20**	Cap'l Spending per sh	**10.10**
25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	47.01	48.88	50.73	52.82	**54.65**	**56.45**	Book Value per sh C	**63.95**
43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	50.42	50.42	50.46	50.52	**50.70**	**51.00**	Common Shs Outst'g D	**52.00**
15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	20.5	22.3	19.9	20.8	*Bold figures are*		Avg Ann'l P/E Ratio	**19.5**
.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	1.19	1.02	1.14	*Value Line*		Relative P/E Ratio	**1.10**
3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	2.6%	2.5%	2.9%	2.9%	*estimates*		Avg Ann'l Div'd Yield	**3.4%**

CAPITAL STRUCTURE as of 6/30/22
Total Debt $2150.7 mill. **Due in 5 Yrs** $325.0 mill.
LT Debt $2075.7 mill. **LT Interest** $100.0 mill.
(LT interest earned: 3.8x)

Pension Assets-12/21 $984.5 mill. **Oblig** $1346.5 mill.

Pfd Stock None

Common Stock 50,560,040 shs. as of 7/29/22

MARKET CAP: $4.9 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1080.7	1246.2	1282.5	1270.3	1262.0	1349.5	1370.8	1346.4	1350.7	1458.1	**1440**	**1460**	Revenues ($mill)	**1780**
168.9	182.4	193.5	194.7	198.3	212.4	226.8	232.9	237.4	245.6	**255**	**270**	Net Profit ($mill)	**310**
13.4%	28.3%	8.0%	19.0%	15.5%	18.6%	7.1%	9.5%	10.8%	13.1%	**13.0%**	**13.0%**	Income Tax Rate	**13.0%**
20.3%	12.3%	13.6%	16.3%	16.3%	13.9%	15.2%	16.2%	17.3%	17.7%	**20.0%**	**21.0%**	AFUDC % to Net Profit	**16.0%**
45.5%	46.6%	45.3%	45.6%	44.8%	43.7%	43.6%	41.3%	43.9%	42.8%	**43.5%**	**47.5%**	Long-Term Debt Ratio	**50.0%**
54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	56.4%	58.7%	56.1%	57.2%	**56.5%**	**52.5%**	Common Equity Ratio	**50.0%**
3225.4	3465.9	3567.6	3783.3	3898.5	3997.5	4205.1	4201.3	4560.4	4669.1	**4920**	**5505**	Total Capital ($mill)	**6675**
3536.0	3665.0	3833.5	3992.4	4172.0	4283.9	4395.7	4531.5	4709.5	4901.8	**5300**	**5800**	Net Plant ($mill)	**6730**
6.5%	6.4%	6.6%	6.2%	6.1%	6.3%	6.4%	6.5%	6.1%	6.2%	**6.0%**	**5.5%**	Return on Total Cap'l	**5.5%**
9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	**9.0%**	**9.0%**	Return on Shr. Equity	**9.0%**
9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	**9.0%**	**9.0%**	Return on Com Equity E	**9.0%**
5.7%	5.6%	5.4%	4.8%	4.3%	4.4%	4.4%	4.2%	3.9%	3.7%	**3.5%**	**3.5%**	Retained to Com Eq	**3.0%**
41%	43%	46%	50%	53%	53%	54%	56%	58%	60%	**61%**	**62%**	All Div'ds to Net Prof	**67%**

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.3	+2.0	+3.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.32	5.38	5.62
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3242	3392	3751
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.5	+2.7	+2.8
Fixed Charge Cov. (%)	307	313	334

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	2.5%	1.5%	*4.0%*
"Cash Flow"	4.5%	4.0%	*4.0%*
Earnings	4.5%	4.0%	*4.0%*
Dividends	8.5%	7.0%	*6.5%*
Book Value	5.0%	4.5%	*4.0%*

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	350.3	316.9	386.3	292.9	1346.4
2020	291.0	318.8	425.3	315.6	1350.7
2021	316.1	360.1	446.9	335.0	1458.1
2022	344.3	358.7	*425*	*312.0*	*1440*
2023	*350*	*360*	*430*	*320*	*1460*

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.84	1.05	1.78	.93	4.61
2020	.74	1.19	2.02	.74	4.69
2021	.89	1.38	1.93	.65	4.85
2022	.91	1.27	*2.00*	*.82*	*5.00*
2023	*.95*	*1.40*	*2.05*	*.85*	*5.25*

QUARTERLY DIVIDENDS PAID B ■ †

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.59	.59	.59	.63	2.40
2019	.63	.63	.63	.67	2.56
2020	.67	.67	.67	.71	2.72
2021	.71	.71	.71	.75	2.88
2022	.75	.75	.75		

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 604,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.3 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 45%; commercial, 24%; industrial, 15%; irrigation, 13%; other, 3%. Generating sources: hydro, 30%; coal, 17%; gas, 15%; purchased, 38%. Fuel costs: 36% of revenues. '21 reported depreciation rate: 2.9%. Has 2,000 employees. Chairman: Richard J. Dahl. President & CEO: Lisa Grow. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

Annual earnings growth at IDACORP is pegged to be 3% and 5%, respectively, in 2022 and 2023. Weather-related usage and transmission wheeling revenues are trending higher, aided by solid population growth in the areas that IDA serves. Air conditioning and irrigation have been primary drivers and should be for the foreseeable future. Too, the likelihood of a rate increase is certainly on the table (more color below) for next year, though nothing is set in stone on that front. With that, we think share net can climb to $5.00 this year, followed by an expected 5% annual increase to $5.25 in 2023.

One would need to go back to 2011 for the most recent rate case in Idaho Power's jurisdiction. That is more than a decade of no rate applications, a period marked by a lofty influx of people into IDA's areas of operation. Management has capital budget plans that will require funding, notably the increased stake it is taking in a transmission line and the financing of larger battery storage capabilities. Dipping in to debt markets will probably be the first move, even as rates are heading north, with an issuance of equity on the slate for 2024.

Capital expenditures are primed for an uptick next year, but should recede after that. For 2022, we look for the cap ex number to come in around $515 million. However, in 2023, we have that amount climbing to $725 million, with the vast majority earmarked for new capacity resources. A recent integrated resources plan came back stating that IDA could have a 125 MW capacity deficit by 2025. This is where using the battery storage comes into the situation. Too, the company's exit from coal-fired manufacturing will require adding significant generation capabilities. A new transmission line will help, but it will not come cheap.

IDACORP's shares are of high quality, but we are not recommending them at this time. For starters, the issue's yield is noticeably below what we deem as average for the utility stocks in our coverage universe. Add to this, the equity has dipped one notch to Below Average (4) on our Timeliness Ranking Scale. Lastly, total return potential three to five years hence does little to quicken the pulse.

Erik M. Manning *October 21, 2022*

(A) Diluted EPS. Excl. nonrecurring gain: '06, 17¢. '19 earnings don't sum due to rounding. Next earnings report due last week of October. (B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '21: $1,462.4 mill., $28.95/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '12: 10% (imputed); earned on avg. com. eq., '21: 9.4%. Regulatory Climate: Above Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	100

NORTHWESTERN NDQ-NWE

RECENT PRICE **49.48** | P/E RATIO **14.5** (Trailing: 14.9; Median: 17.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **5.2%** | VALUE LINE

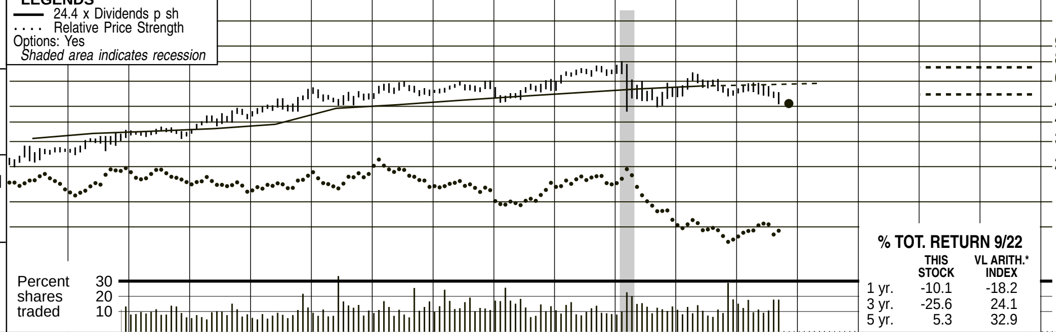
TIMELINESS	5	Lowered 9/9/22
SAFETY	2	Raised 7/27/18
TECHNICAL	3	Raised 10/21/22

BETA .90 (1.00 = Market)

High:	36.6	38.0	47.2	58.7	59.7	63.8	64.5	65.7	76.7	80.5	70.8	63.1
Low:	27.4	33.0	35.1	42.6	48.4	52.2	55.7	50.0	57.3	45.1	53.2	49.1

Target Price Range 2025 | 2026 | 2027

LEGENDS
— 24.4 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$46-$69	$58 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+50%)	15%
Low	55	(+10%)	8%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	170	154	140
to Sell	105	111	121
Hld's(000)	56973	57800	56756

Percent shares traded 30 20 10

% TOT. RETURN 9/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-10.1	-18.2
3 yr.	-25.6	24.1
5 yr.	5.3	32.9

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	23.81	24.93	23.70	25.38	24.15	23.55	Revenues per sh	25.75
3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	6.96	7.07	6.86	6.92	6.70	6.85	"Cash Flow" per sh	8.00
1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	3.40	3.53	3.21	3.50	3.35	3.55	Earnings per sh A	4.00
1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	2.20	2.30	2.40	2.48	2.52	2.56	Div'd Decl'd per sh B ■ †	2.68
2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60	5.64	6.26	8.02	8.03	10.05	9.10	Cap'l Spending per sh	6.50
20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	38.60	40.42	41.10	43.28	44.60	46.30	Book Value per sh C	50.00
35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	50.32	50.45	50.59	54.06	58.00	62.00	Common Shs Outst'g D	62.00
26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	16.8	19.9	18.6	17.4	Bold figures are		Avg Ann'l P/E Ratio	16.5
1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	1.06	.96	.94	Value Line		Relative P/E Ratio	.90
3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	3.9%	3.3%	4.0%	4.1%	estimates		Avg Ann'l Div'd Yield	4.1%

CAPITAL STRUCTURE as of 6/30/22
Total Debt $2533.4 mill. **Due in 5 Yrs** $1037.4 mill.
LT Debt $2530.4 mill. **LT Interest** $87.8 mill.
Incl. $11.9 mill. finance leases.
(Total Interest Coverage: 2.7x)

Pension Assets-12/21 $605.5 mill. **Oblig** $696.8 mill.

Pfd Stock None

Common Stock 56,150,050 shs. as of 7/22/22

MARKET CAP: $2.8 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	1198.1	1257.9	1198.7	1372.3	1400	1460	Revenues ($mill)	1600
83.7	94.0	120.7	138.4	164.2	162.7	171.1	179.3	162.6	181.6	190	215	Net Profit ($mill)	250
9.6%	13.2%	- -	13.7%	- -	7.6%	- -	1.6%	1.6%	.9%	1.5%	3.0%	Income Tax Rate	12.0%
9.4%	8.7%	8.9%	9.8%	4.3%	5.2%	3.4%	4.6%	6.0%	14.9%	16.0%	14.0%	AFUDC % to Net Profit	10.0%
53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	52.2%	52.5%	52.8%	52.2%	50.0%	49.5%	Long-Term Debt Ratio	49.0%
46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	47.8%	47.5%	47.2%	47.8%	50.0%	50.5%	Common Equity Ratio	51.0%
2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	4064.6	4289.8	4409.1	4893.1	5195	5675	Total Capital ($mill)	6050
2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	4521.3	4700.9	4952.9	5247.2	5630	5980	Net Plant ($mill)	6550
5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	5.2%	5.2%	4.6%	4.6%	4.5%	4.5%	Return on Total Cap'l	5.0%
9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	7.5%	7.5%	Return on Shr. Equity	8.0%
9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	7.5%	7.5%	Return on Com Equity E	8.0%
3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	3.2%	3.1%	2.0%	2.3%	2.0%	2.0%	Retained to Com Eq	2.5%
65%	61%	54%	65%	58%	62%	64%	64%	74%	71%	75%	72%	All Div'ds to Net Prof	67%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+4.6	-4.4	+.7
Avg. Indust. Use (MWH)	37808	33526	31792
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2237	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.2	+1.6
Fixed Charge Cov. (%)	284	237	252

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	.5%
"Cash Flow"	3.5%	3.0%	2.5%
Earnings	4.5%	2.0%	2.5%
Dividends	5.5%	5.5%	2.0%
Book Value	6.0%	4.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	384.2	270.7	274.8	328.2	1257.9
2020	335.3	269.4	280.6	313.4	1198.7
2021	400.8	298.2	326.0	347.3	1372.3
2022	394.5	323.0	330.5	352	1400
2023	415	330	345	370	1460

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.44	.49	.42	1.18	3.53
2020	1.00	.43	.58	1.21	3.21
2021	1.24	.59	.70	.97	3.50
2022	1.08	.58	.64	1.05	3.35
2023	1.15	.60	.70	1.10	3.55

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.55	.55	.55	.55	2.20
2019	.575	.575	.575	.575	2.30
2020	.60	.60	.60	.60	2.40
2021	.62	.62	.62	.62	2.48
2022	.63	.63	.63		

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 456,000 electric customers in Montana and South Dakota and 298,000 gas customers in Montana (85% of gross margin), South Dakota (14%), and Nebraska (1%). Electric revenue breakdown: residential, 43%; commercial, 49%; industrial, 4%; other, 4%. Generating sources: coal, 28%; hydro, 27%; wind, 6%; other, 4%; purchased, 35%. Fuel costs: 31% of revenues. '21 reported deprec. rate: 2.8%. Has 1,500 employees. Chairman: Dana J. Dykhouse. CEO: Robert C. Rowe. President & COO: Brian B. Bird. Inc.: DE. Address: 3010 West 69th Street, Sioux Falls, SD 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern shares have flatlined for years, commensurate with EPS. Since 2015, this issue has mainly traded within the $50-$60 price range, breaking out briefly from time to time. While net profits have grown gradually over the past several years (the 2016-2022 average annual rate is 2%), shares outstanding have also risen, diluting per-share gains. The main constraint, besides dilution, has been years of underearning the utility's allowable ROE. This is largely due to the relative constraints of the rate-relief mechanisms available in the company's utility territories, which results in regulatory lag. In other words, the company foots the bill for grid maintenance and upgrades but has to justify it and wait for the payback.

Management has a solid plan in place that should help reignite growth. In an effort to become less reliant on purchased power, while modernizing and shoring up reliability, the company is looking to add significant gas-fired capacity in both South Dakota and Montana. An $83 million, 58-megawatt plant in South Dakota was completed in the second quarter. And in April, NWE broke ground on a $275 million, 175-mw facility in Montana, expected to be operational by late 2023. Financing is via a $200 million equity offering ($53.50 a share) completed in fourth quarter 2021, with $300 million more expected in early 2023 via a forward sale.

Results depend on an upcoming general rate case decision. NWE has filed its case, and likely will obtain rate relief early next year. The company is also asking for pricing mechanisms that would help alleviate regulatory lag. This may be a tough sell in a historically difficult regulatory environment. Assuming the capacity expansion is allowed to proceed, it would lift the rate base and help to narrow the gap between NWE's earned and allowable ROE. Our projections assume an annual growth rate in share net from 2023 to mid-decade of 4%. It's somewhat below the industry average, yet significantly better than what's transpired in recent years.

This issue is untimely. However, at the recent valuation there may be some appeal for utility investors seeking outsized income. The yield is 115 basis points above the electric utility industry median.

Anthony J. Glennon *October 21, 2022*

(A) Diluted EPS. Excl. nonrec. gains/(losses): '12, 40¢; '15, 27¢; '18, 52¢; '19, 45¢; '20, (15¢); '21, 10¢; Q1-Q2 '22, (4¢). '20 EPS don't sum due to rounding. Next egs. report due late Oct. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd charges. In '21: $19.39/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '19 (elec.): 9.65%; in '17 (gas): 9.55%; in SD in '15: none specified; in NE in '07: 10.4%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	90

OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 39.75 | P/E RATIO 18.0 (Trailing: 17.5 Median: 17.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 5/20/22
SAFETY 2 Lowered 12/18/15
TECHNICAL 3 Lowered 12/9/22
BETA 1.00 (1.00 = Market)

High:	28.6	30.1	40.0	39.3	36.5	34.2	37.4	41.8	45.8	46.4	38.6	42.9	
Low:	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6	38.0	23.0	29.2	33.3	

Target Price Range
2025 | 2026 | 2027

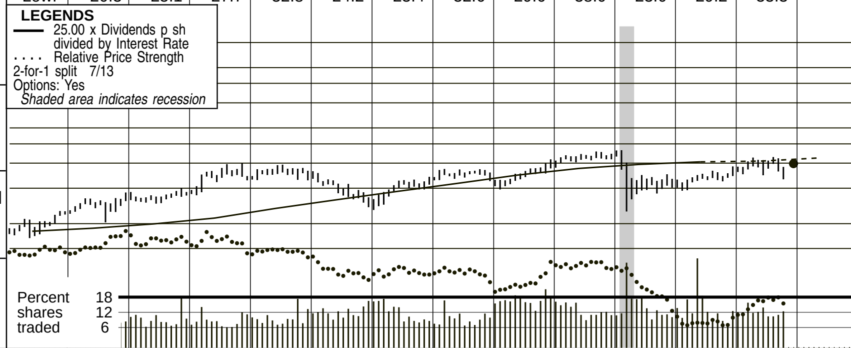
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$33-$51 $42 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+40%)	12%
Low	40	(Nil)	4%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	228	218	185
to Sell	170	182	192
Hld's(000)	129869	136256	136256



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.3	-13.4
3 yr.	-3.1	35.8
5 yr.	22.1	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	11.37	11.15	10.61	18.26	*16.00*	*16.50*	Revenues per sh	*18.25*
2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	3.74	4.02	4.03	4.44	*4.45*	*4.40*	"Cash Flow" per sh	*6.25*
1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	2.12	2.24	2.08	2.36	*2.25*	*2.10*	Earnings per sh A	*3.25*
.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	1.58	1.63	*1.64*	*1.70*	Div'd Decl'd per sh B ■	*1.85*
2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	2.87	3.18	3.25	3.89	*4.75*	*4.75*	Cap'l Spending per sh	*4.75*
8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	20.06	20.69	18.15	20.27	*21.25*	*22.25*	Book Value per sh C	*26.00*
182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	199.70	200.10	200.10	200.10	*200.20*	*200.20*	Common Shs Outst'g D	*200.20*
13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	16.5	19.0	16.2	14.3	Bold figures are		Avg Ann'l P/E Ratio	*14.0*
.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.01	.83	.76	Value Line		Relative P/E Ratio	*.80*
4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	4.0%	3.5%	4.7%	4.8%	estimates		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $5279.5 mill. **Due in 5 Yrs** $1731.5 mill.
LT Debt $3548.0 mill. **LT Interest** $158.7 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $5.7 mill.

Pension Assets-12/21 $486.0 mill. **Oblig** $502.9 mill.

Pfd Stock None

Common Stock 200,202,672 shs.

MARKET CAP: $8.0 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	2270.3	2231.6	2122.3	3653.7	*3200*	*3300*	Revenues ($mill)	*3650*
355.0	387.6	395.8	337.6	338.2	384.3	425.5	449.6	415.9	472.5	*450*	*420*	Net Profit ($mill)	*665*
26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	14.5%	7.4%	13.2%	11.5%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	8.3%	1.6%	1.6%	2.2%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	42.0%	43.6%	49.0%	52.6%	*46.0%*	*52.0%*	Long-Term Debt Ratio	*50.0%*
49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	51.0%	47.4%	*53.0%*	*48.0%*	Common Equity Ratio	*50.0%*
5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	6902.0	7334.7	7126.2	8552.7	*8100*	*9400*	Total Capital ($mill)	*10400*
8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	8643.8	9044.6	9374.6	9832.9	*10345*	*10830*	Net Plant ($mill)	*12075*
7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	7.3%	7.1%	6.9%	6.4%	*7.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	*12.0%*	*12.0%*	Return on Shr. Equity	*13.0%*
12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	*12.0%*	*12.0%*	Return on Com Equity E	*13.0%*
7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	3.8%	3.6%	2.8%	3.6%	*4.0%*	*4.5%*	Retained to Com Eq	*5.5%*
44%	43%	47%	61%	67%	64%	64%	67%	76%	69%	*73%*	*81%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.1	-4.9	+2.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.69	4.40	7.68
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6817	6437	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.1	+1.4
Fixed Charge Cov. (%)	335	326	336

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.0%	3.0%	*5.5%*
"Cash Flow"	3.5%	4.5%	*7.0%*
Earnings	4.0%	4.5%	*6.5%*
Dividends	8.0%	8.5%	*3.0%*
Book Value	5.5%	3.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	490.0	513.7	755.4	472.5	2231.6
2020	431.3	503.5	702.1	485.4	2122.3
2021	1630.6	577.4	864.4	581.3	3653.7
2022	589.3	803.7	1270.8	*536.2*	*3200*
2023	*600*	*800*	*1200*	*700*	*3300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.24	.50	1.25	.26	2.24
2020	.23	.51	1.04	.30	2.08
2021	.26	.56	1.26	.27	2.36
2022	.33	.36	1.31	*.25*	*2.25*
2023	*.32*	*.33*	*1.25*	*.20*	*2.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.3325	.3325	.3325	.365	1.36
2019	.365	.365	.365	.388	1.48
2020	.3875	.3875	.3875	.4025	1.57
2021	.4025	.4025	.4025	.41	1.62
2022	.41	.41	.41	.4141	

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 879,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 3% of Energy Transfer's limited partnership units. Electric revenue breakdown: residential, 44%; commercial, 25%; industrial, 11%; oilfield, 10%; other, 10%. Generating sources: gas, 25%; coal, 21%; wind, 6%; purchased, 48%. Fuel costs: 58% of revenues. '21 reported depreciation rate (utility): 2.6%. Has 2,200 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321. Tel.: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary in Oklahoma agreed to a $30 million settlement in its general rate case. The company initially requested a $164 million increase which was reduced drastically by the Oklahoma Corporation Commission after regulatory hearings. The commission is now considering spreading out monthly price increases of $9.72 over a three to four year time frame, compared to the current two-year span to help mitigate the impact on customer bills. In Arkansas, the utility implemented its new fuel rates which went into effect on November 1st. The increases will recover $40 million over the next 17 months.

We see earnings declining through 2023. Management continues to expect long-term share-earnings growth of 5%-7% annually, based off 2021 profits. (Excluding equity income.) For 2022, the company expects share earnings in a range of $2.08-$2.12 a share. Our full-year 2022 and 2023 bottom-line estimates are $2.25 a share (including equity income from Energy Transfer stake), and $2.10 a share, respectively. We have lowered our 2023 forecasts due to the macroeconomic climate, including margin pressures from rising interest rates, along with depreciation rates and pending rate reviews.

In the third quarter, OGE completed its transformation to an electric utility, after selling its Energy Transfer units. The exit from midstream operations should reduce business risk and attract investors as it becomes a pure-play electric utility. The natural gas midstream segment has long been a weakness, and the exit should improve performance.

These shares are ranked to mirror the broader market averages in the coming six to 12 months. Equities in the utilties industry have faced immense pressure as of late due to rising interest rates. Rising Treasury yields are becoming more appealing to income-oriented investors, challenging the attractiveness of the utility industry. As a result, the stock is down more than 5% in value since our last report in September. While total return potential is below average for the 18-month and 3- to 5-year period, these shares hold an attractive dividend yield that is well above the utility average.

Zachary J. Hodgkinson December 9, 2022

(A) Diluted EPS. Excl. nonrecurring gains (losses): '15, (33¢); '17, $1.18; '19, (8¢); '20, ($2.95); '21, $1.32; '22, $1.06; gain on discont. ops.: '06, 20¢. '19 & '21 EPS don't sum due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '21: $6.15/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '19: 9.5%; in AR in '18: 9.5%; earned on avg. com. eq., '21: 12.7%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	95

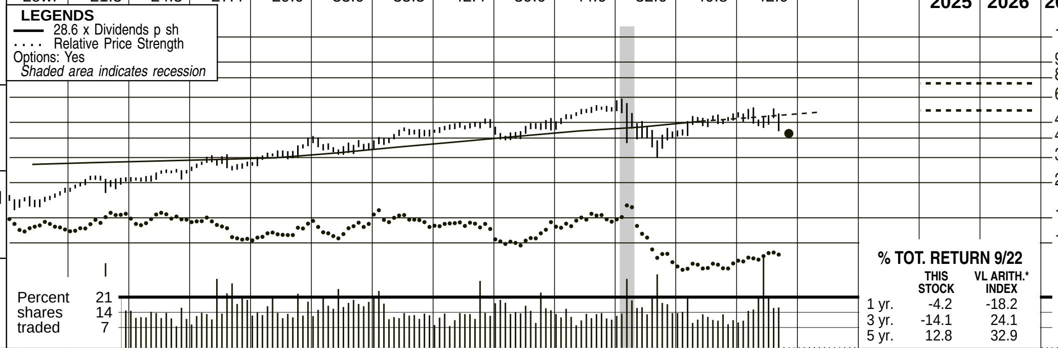
PORTLAND GENERAL NYSE-POR

RECENT PRICE **42.17** | P/E RATIO **14.4** (Trailing: 15.7 / Median: 18.0) | RELATIVE P/E RATIO **0.98** | DIV'D YLD **4.4%** | VALUE LINE

TIMELINESS 3 Raised 10/7/22
SAFETY 2 Raised 10/22/21
TECHNICAL 1 Raised 9/23/22
BETA .85 (1.00 = Market)

High:	26.0	28.1	33.3	40.3	41.0	45.2	50.1	50.4	58.4	63.1	53.1	57.0
Low:	21.3	24.3	27.4	29.0	33.0	35.3	42.4	39.0	44.0	32.0	40.8	42.0

Target Price Range
2025 | 2026 | 2027



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$44-$70	$57 (35%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+80%)	19%
Low	55	(+30%)	11%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	149	178	181
to Sell	141	142	153
Hld's(000)	81443	82974	89213

% TOT. RETURN 9/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.2	-18.2
3 yr.	-14.1	24.1
5 yr.	12.8	32.9

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	22.30	23.75	23.96	26.80	*27.35*	*28.20*	Revenues per sh	*30.75*
4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	6.65	6.97	7.83	7.25	*7.60*	*8.05*	"Cash Flow" per sh	*9.40*
1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	2.37	2.39	2.75	2.72	*2.80*	*2.95*	Earnings per sh A	*3.45*
.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	1.43	1.52	1.59	1.70	*1.79*	*1.89*	Div'd Decl'd per sh B ■ †	*2.24*
5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	6.67	6.78	8.76	7.11	*7.65*	*7.55*	Cap'l Spending per sh	*7.60*
19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	28.07	28.99	29.18	30.28	*31.25*	*32.35*	Book Value per sh C	*35.80*
62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	89.27	89.39	89.54	89.41	*89.50*	*89.50*	Common Shs Outst'g D	*89.50*
23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	18.4	22.3	16.6	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	1.19	.85	.95	*Value Line*		Relative P/E Ratio	*1.05*
2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	3.3%	2.8%	3.5%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $3604 mill. **Due in 5 Yrs** $186 mill.
LT Debt $3583 mill. **LT Interest** $128 mill.
Incl. $273 mill. finance leases.
(Total Interest Coverage: 2.9x)
Leases, Uncapitalized Annual rentals $4 mill.
Pension Assets-12/21 $800 mill.
Oblig $972 mill.
Pfd Stock None

Common Stock 89,242,847 shs.
as of 7/21/22

MARKET CAP: $3.8 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1805.0	1810.0	1900.0	1898.0	1923.0	2009.0	1991.0	2123.0	2145.0	2396.0	*2450*	*2525*	Revenues ($mill)	*2750*
141.0	137.0	175.0	172.0	193.0	204.0	212.0	214.0	247.0	244.0	*250*	*265*	Net Profit ($mill)	*310*
31.4%	23.2%	26.0%	20.7%	20.6%	25.3%	7.4%	11.2%	12.4%	8.6%	*17.5%*	*17.5%*	Income Tax Rate	*17.5%*
7.1%	14.6%	33.7%	19.8%	16.6%	8.8%	8.0%	7.0%	9.7%	10.2%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
47.1%	51.3%	52.7%	47.8%	48.4%	50.1%	46.5%	51.3%	53.6%	56.8%	*55.5%*	*56.0%*	Long-Term Debt Ratio	*57.5%*
52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	53.5%	48.7%	46.4%	43.2%	*44.5%*	*44.0%*	Common Equity Ratio	*42.5%*
3264.0	3735.0	4037.0	4329.0	4544.0	4842.0	4684.0	5323.0	5628.0	6265.0	*6315*	*6565*	Total Capital ($mill)	*7575*
4392.0	4880.0	5679.0	6012.0	6434.0	6741.0	6887.0	7161.0	7539.0	8005.0	*8260*	*8480*	Net Plant ($mill)	*9000*
5.9%	5.1%	5.8%	5.4%	5.6%	5.5%	5.8%	5.1%	5.6%	4.9%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
3.5%	2.9%	4.6%	3.3%	3.5%	3.6%	3.5%	3.1%	4.1%	3.5%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
57%	61%	50%	56%	57%	58%	59%	63%	57%	61%	*64%*	*64%*	All Div'ds to Net Prof	*65%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.2	+.4	+5.1
Avg. Indust. Use (MWH)	17827	18472	20002
Avg. Indust. Revs. per KWH (¢)	4.75	4.99	5.22
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3765	3771	4447
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.5	+.6
Fixed Charge Cov. (%)	265	187	261

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	0.5%	2.0%	*3.5%*
"Cash Flow"	5.0%	5.0%	*4.0%*
Earnings	5.0%	4.5%	*4.5%*
Dividends	4.5%	6.0%	*6.0%*
Book Value	3.5%	3.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	573.0	460.0	542.0	548.0	2123.0
2020	573.0	469.0	547.0	556.0	2145.0
2021	609.0	537.0	642.0	608.0	2396.0
2022	626.0	591.0	*633*	*600*	*2450*
2023	*645*	*580*	*660*	*640*	*2525*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.82	.28	.61	.68	2.39
2020	.91	.43	.84	.57	2.75
2021	1.07	.36	.56	.73	2.72
2022	.67	.72	*.65*	*.76*	*2.80*
2023	*.80*	*.65*	*.70*	*.80*	*2.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.34	.34	.3625	.3625	1.41
2019	.3625	.3625	.385	.385	1.50
2020	.385	.385	.385	.4075	1.56
2021	.4075	.4075	.43	.43	1.68
2022	.43	.43	.4525	.4525	

BUSINESS: Portland General Electric Company (PGE) provides electricity to 917,000 customers in 51 cities in a 4,000-square-mile area of Oregon, including Portland and Salem (population: 1.9 million). The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 29%; industrial, 11%; other, 13%. Generating sources: gas, 37%; wind, 9%; coal, 8%; hydro, 4%; purchased, 42%. Fuel costs: 34% of revenues. '21 reported depreciation rate: 3.4%. Has 2,800 full-time employees. Chairman: Jack E. Davis. President and Chief Executive Officer: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, OR 97204. Tel.: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric (PGE) is having a good year, prompting management to lift guidance. To briefly recap, PGE received its general rate case decision from OPUC (Oregon Public Utility Commission) in late April, authorizing a 3.2% price hike. And during the first half of the year, the company profited from higher retail energy deliveries, due to continued growth in industrial demand, including high-tech and digital customers. PGE revised its 2022 GAAP-based share-earnings guidance up by a dime on both sides of the range, to $2.60-$2.75. Our estimate is higher, as we're excluding deferral reductions related to year ended 2020.

The utility is still awaiting finalized decisions on its RFP (request for proposals). PGE wants to add at least 375 to 500 megawatts of renewables and "nonemitting" capacity. In July, OPUC acknowledged PGE's submitted shortlist of bids in the pending RFP. The proposals provide various combinations of wind, solar, and battery storage options that include power purchase agreements along with company-owned resources. The goal remains for contracts to be executed with the winning bidders by year end.

PGE leadership's long-term earnings growth target of 4%-6% looks achievable. Next year will benefit from a full year of rate relief against an easy comparison. From 2023 out to mid-decade we're projecting a 5.5% growth rate in earnings. Accelerating load growth, thanks to the healthy economy of the utility's service territory, where there is a vibrant tech sector, is a key factor.

The board of directors raised the payout 5.2% this year. PGE targets a long-term growth rate of 5%-7% and a payout ratio of 60%-70%. Our projections assume a 6% rate of growth to mid-decade.

Utility investors may want to consider this issue for a long-term holding. Neutrally ranked PGE offers a healthy dividend yield that's 40 basis points above the electric utility median. This despite EPS and dividend growth rates being decently above the industry averages. Market weakness has the stock down 13% since our July report, and near the bottom of our 18-month Target Price Range, thereby offering solid recovery potential.

Anthony J. Glennon *October 21, 2022*

(A) Diluted earnings. Excl. nonrecurring gains/(losses): '13, (42¢); '17, (19¢); '20, ($1.03); '22, (14¢). Next earnings report due October 25th.
(B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available.
(C) Incl. deferred charges. In '21: $533 mill., $5.96/sh. (D) In mill.
(E) Rate base: Net original cost. Rate allowed on common equity in '22: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	95

XCEL ENERGY NDQ-XEL

RECENT PRICE 60.21 | P/E RATIO 18.8 (Trailing: 20.0 Median: 19.0) | RELATIVE P/E RATIO 1.28 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Raised 12/31/21
SAFETY 1 Raised 5/1/15
TECHNICAL 1 Raised 10/21/22
BETA .80 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$64-$99 $82 (35%)

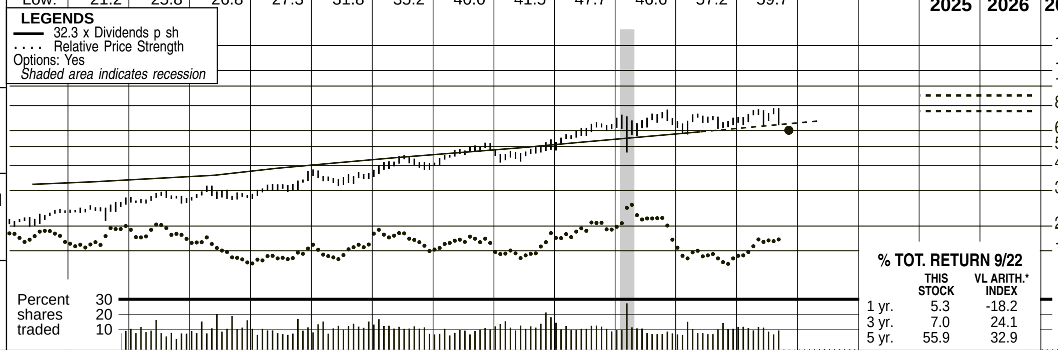
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+50%)	13%
Low	75	(+25%)	9%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	449	458	453
to Sell	338	340	368
Hld's(000)	413762	418018	424573

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	27.8	29.9	31.8	37.6	38.3	45.4	52.2	54.1	66.1	76.4	72.9	77.7
Low:	21.2	25.8	26.8	27.3	31.8	35.2	40.0	41.5	47.7	46.6	57.2	59.7



% TOT. RETURN 9/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.3	-18.2
3 yr.	7.0	24.1
5 yr.	55.9	32.9

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	22.44	21.98	21.45	24.69	*25.90*	*26.35*	Revenues per sh	*28.50*
3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	5.92	6.25	6.61	7.08	*7.75*	*8.30*	"Cash Flow" per sh	*10.00*
1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	2.47	2.64	2.79	2.96	*3.15*	*3.35*	Earnings per sh A	*4.00*
.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	1.62	1.72	1.83	*1.95*	*2.08*	Div'd Decl'd per sh B ■ †	*2.50*
4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	7.70	8.05	9.99	7.80	*9.65*	*9.00*	Cap'l Spending per sh	*9.00*
14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	23.78	25.24	27.12	28.70	*30.15*	*31.65*	Book Value per sh C	*37.00*
407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	514.04	524.54	537.44	544.03	*547.00*	*550.00*	Common Shs Outst'g D	*561.00*
14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	18.9	22.3	23.9	22.5	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.19	1.23	1.23	*Value Line*		Relative P/E Ratio	*1.10*
4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	3.3%	2.7%	2.6%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $23992 mill. **Due in 5 Yrs** $4911 mill.
LT Debt $23205 mill. **LT Interest** $809 mill.
Incl. $73 mill. finance leases.
(Total Interest Coverage: 2.9x)

Leases, Uncapitalized Annual rentals $69 mill.
Pension Assets-12/21 $3670 mill. **Oblig** $3718 mill.

Pfd Stock None

Common Stock 546,991,330 shs.
as of 7/21/22
MARKET CAP: $32.9 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
10128	10915	11686	11024	11107	11404	11537	11529	11526	13431	*14175*	*14500*	Revenues ($mill)	*16000*
905.2	948.2	1021.3	1063.6	1123.4	1171.0	1261.0	1372.0	1473.0	1597.0	*1720*	*1855*	Net Profit ($mill)	*2260*
33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	12.6%	8.5%	8.5%	- -	*NMF*	*NMF*	Income Tax Rate	*NMF*
10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	12.4%	8.3%	10.7%	6.2%	*7.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	56.4%	56.8%	57.4%	58.2%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*58.0%*
46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	42.6%	41.8%	*42.0%*	*42.0%*	Common Equity Ratio	*42.0%*
19018	20477	21714	23092	25216	25975	28025	30646	34220	37391	*39150*	*41600*	Total Capital ($mill)	*49200*
23809	26122	28757	31206	32842	34329	36944	39483	42950	45457	*48225*	*50475*	Net Plant ($mill)	*57000*
6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	5.7%	5.6%	5.4%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	*10.5%*	*10.5%*	Return on Com Equity E	*11.0%*
4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	4.2%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
54%	54%	55%	57%	61%	62%	58%	58%	58%	59%	*62%*	*62%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.2	-2.3	+1.4
Large C & I Use (MWH)	NA	NA	NA
Large C & I Revs. per KWH (¢)	5.96	5.78	6.60
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	20146	19665	19849
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	NA	NA
Fixed Charge Cov. (%)	272	252	262

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	.5%	*4.0%*
"Cash Flow"	6.5%	7.5%	*7.0%*
Earnings	6.0%	6.0%	*6.0%*
Dividends	5.5%	6.0%	*6.5%*
Book Value	5.0%	5.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3141	2577	3013	2798	11529
2020	2811	2586	3182	2947	11526
2021	3541	3068	3467	3355	13431
2022	3751	3424	*3900*	*3100*	*14175*
2023	*3875*	*3450*	*4000*	*3175*	*14500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.61	.46	1.01	.56	2.64
2020	.56	.54	1.14	.54	2.79
2021	.67	.58	1.13	.58	2.96
2022	.70	.60	*1.23*	*.62*	*3.15*
2023	*.75*	*.65*	*1.30*	*.65*	*3.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.36	.38	.38	.38	1.50
2019	.38	.405	.405	.405	1.60
2020	.405	.43	.43	.43	1.70
2021	.43	.4575	.4575	.4575	1.80
2022	.4575	.4875	.4875	.4875	

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power Company (NSP), which supplies electricity to MN, WI, ND, SD & MI & gas to MN, WI, ND & MI; Public Service Company of Colorado (PSCo), which supplies electricity & gas to CO; & Southwestern Public Service Company (SPS), which supplies electricity to TX and NM. Customers: 3.7 mill. electric, 2.1 mill. gas. Electric revenue breakdown: residential, 31%; small comm'l & ind'l, 36%; large comm'l & ind'l, 18%; other, 15%. Generating sources not available. Fuel costs: 43% of revenues. '21 reported deprec. rate: 3.5%. Has 11,300 employees. Chrmn: Ben Fowke. Pres. & CEO: Bob Frenzel. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

At Xcel Energy, rate relief should continue to drive steady earnings gains. Upcoming price hikes will be largely due to the approval of renewable-energy projects inclusion in the rate base, for which regulated utilities are allowed to earn a specified return on equity (ROE). The company is also effectively controlling costs despite inflationary headwinds. Our 2022 earnings estimate remains at the midpoint of Xcel's reaffirmed guidance of $3.10-$3.20 per share, given that first-half results were in line with expectations. (Entering this year our first-half share-net estimate tally was $1.33; Xcel earned $1.30 per share.) Meanwhile, our projections for 6%-6.5% profit gains in 2023 and beyond are based on the same factors. Namely, growing the rate base at its utility subsidiaries as Xcel works with its regulatory commissions to bring about a green-energy future. Company leadership has a stated earnings and dividend growth objective of 5%-7% and a solid track record that underscores its goal (see Annual Rates box). Notably, a consistently solid ROE has been delivered during both good and difficult economic times.

Xcel has numerous renewable-energy proposals up for review. The Colorado commission approved Xcel's resource plan, which includes about 4,000 megawatts (mw) of renewable (e.g., wind and solar) additions and the conversion of a major plant from coal to natural gas. This is in addition to the approved Minnesota plan, which adds 6,000 mw of renewables. RFPs (request for proposals) are being filed and commission decisions on the finer details are expected in the second half of next year. In the electric-vehicle (EV) arena, Xcel is making progress on its goal to power 1.5 million EVs by 2030. It filed transportation plans in Minnesota and Wisconsin in the third quarter. The company is looking to accelerate EV adoption through the development of high-speed public charging infrastructure in partnership with its states.

This high-quality issue offers utility investors solid risk-adjusted 3- to 5-year total returns. Its valuation is down 14% since our July report. The stock has significant recovery potential to the midpoint of our 18-month Target Price Range.

Anthony J. Glennon *October 21, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (loss) on discontinued ops.: '06, 1¢; '09, (1¢); '10, 1¢. '20 EPS don't sum due to rounding. Next earnings report due late October. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '21: $2738 mill., $4.42/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on common equity (blended): 9.6%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	100

The Potomac Edison Company
Summary of Risk Premium Models for the
Proxy Group of Thirteen Electric Utilities

		Proxy Group of Thirteen Electric Utilities	
Predictive Risk Premium Model (PRPM) (1)		11.95	%
Risk Premium Using an Adjusted Total Market Approach (2)		11.33	
	Average	11.64	%

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.

The Potomac Edison Company
Indicated ROE
Derived by the Predictive Risk Premium Model (1)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Thirteen Electric Utilities	LT Average Predicted Variance	Spot Predicted Variance	Recommended Variance (2)	GARCH Coefficient	Predicted Risk Premium (3)	Risk-Free Rate (4)	Indicated ROE (5)
Alliant Energy Corporation	0.28%	0.43%	0.28%	2.5640	8.84%	3.91%	12.75%
Ameren Corporation	0.23%	0.35%	0.23%	2.0106	5.77%	3.91%	9.68%
American Electric Power Corporation	0.29%	0.44%	0.29%	2.3326	8.35%	3.91%	12.26%
Duke Energy Corporation	0.31%	0.40%	0.31%	1.8383	7.14%	3.91%	11.05%
Edison International	0.43%	0.65%	0.43%	1.4762	7.98%	3.91%	11.89%
Entergy Corporation	0.40%	0.51%	0.40%	2.2043	11.22%	3.91%	15.13%
Evergy, Inc.	0.49%	0.84%	0.49%	1.3060	7.99%	3.91%	11.90%
Eversource Energy	0.31%	0.46%	0.31%	1.6024	6.15%	3.91%	10.06%
IDACORP, Inc.	0.29%	0.34%	0.29%	2.1876	7.85%	3.91%	11.76%
NorthWestern Corporation	0.34%	0.53%	0.34%	2.2110	9.28%	3.91%	13.19%
OGE Energy Corporation	0.31%	0.41%	0.31%	2.1939	8.46%	3.91%	12.37%
Portland General Electric Company	0.30%	0.56%	0.30%	1.6998	6.39%	3.91%	10.30%
Xcel Energy Inc.	0.28%	0.37%	0.28%	2.7770	9.62%	3.91%	13.53%
						Average	11.99%
						Median	11.90%
						Average of Mean and Median	11.95%

Notes:

(1) The Predictive Risk Premium Model uses historical data to generate a predicted variance and a GARCH coefficient. The historical data used are the equity risk premiums for the first available trading month as reported by Bloomberg Professional Service.

(2) In view of the current increased volatility, Mr. D'Ascendis recommends the long-term predicted variance at this time.

(3) $(1+(\text{Column [3]} * \text{Column [4]})^{12}) - 1$.

(4) From note 2 on page 2 of Schedule DWD-4.

(5) Column [5] + Column [6].

The Potomac Edison Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Thirteen Electric Utilities
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.05 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.83
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.88 %
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group (3)	0.20
5.	Adjusted Prospective Bond Yield	6.08 %
6.	Equity Risk Premium (4)	5.25
7.	Risk Premium Derived Common Equity Cost Rate	11.33 %

Notes:
(1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 10 and 11 of this Schedule).
(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.83% from page 4 of this Schedule.
(3) Adjustment to reflect the Baa1 Moody's LT issuer rating of the Electric Utility Proxy Group as shown on page 5 of this Schedule. The 0.20% upward adjustment is derived by taking 2/3 of the spread between A2 and Baa2 Public Utility Bonds (2/3 * 0.3% = 0.20%) as derived from page 4 of this Schedule.
(4) From page 7 of this Schedule.

The Potomac Edison Company
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1] Aaa Rated Corporate Bond	[2] A2 Rated Public Utility Bond	[3] Baa2 Rated Public Utility Bond
Dec-2022	4.41 %	5.27 %	5.56 %
Nov-2022	4.90	5.75	6.05
Oct-2022	5.10	5.88	6.18
Average	4.80 %	5.63 %	5.93 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:
0.83 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds:
0.30 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services

The Potomac Edison Company
Comparison of Long-Term Issuer Ratings for
Proxy Group of Thirteen Electric Utilities

Proxy Group of Thirteen Electric Utilities (2)	Moody's Long-Term Issuer Rating December 2022		Standard & Poor's Long-Term Issuer Rating December 2022	
	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Alliant Energy Corporation	A3/Baa1	7.5	A/A-	6.5
Ameren Corporation	A3	7.0	BBB+	8.0
American Electric Power Corporation	Baa1	8.0	A-	7.0
Duke Energy Corporation	A3	7.0	BBB+	8.0
Edison International	Baa2	9.0	BBB	9.0
Entergy Corporation	Baa1	8.0	BBB+	8.0
Evergy, Inc.	Baa1	8.0	A-	7.0
Eversource Energy	A3	7.0	A-	7.0
IDACORP, Inc.	Baa1	8.0	BBB	9.0
NorthWestern Corporation	Baa2	9.0	BBB	9.0
OGE Energy Corporation	A3	7.0	A-	7.0
Portland General Electric Company	A3	7.0	BBB+	8.0
Xcel Energy Inc.	A3	7.0	A-	7.0
Average	Baa1	7.7	BBB+	7.7

Notes:
(1) From page 6 of this Schedule.
(2) Based on the ratings of the subsidaries for Utility Proxy Group

Source of Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

The Potomac Edison Company
Judgment of Equity Risk Premium for the
Proxy Group of Thirteen Electric Utilities

Line No.		Proxy Group of Thirteen Electric Utilities
1.	Calculated equity risk premium based on the total market using the beta approach (1)	6.67 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A2 rated bonds (2)	4.32
3.	Predicted Equity Risk Premium Based on Regression Analysis of 1207 Fully-Litigated Electric Utility Rate Cases (3)	4.77
4.	Average equity risk premium	5.25 %

Notes: (1) From page 8 of this Schedule.
(2) From page 12 of this Schedule.
(3) From pages 13 of this Schedule.

The Potomac Edison Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Thirteen Electric Utilities

Line No.	Equity Risk Premium Measure	Proxy Group of Thirteen Electric Utilities
1.	Kroll Equity Risk Premium (1)	6.13 %
2.	Regression on Kroll Risk Premium Data (2)	7.26
3.	Kroll Equity Risk Premium based on PRPM (3)	9.76
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	11.53
5.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	10.62
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	6.01
7.	Conclusion of Equity Risk Premium	8.55 %
8.	Adjusted Beta (7)	0.78
9.	Forecasted Equity Risk Premium	6.67 %

Notes provided on page 9 of this Schedule.

The Potomac Edison Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Thirteen Electric Utilities

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll 2022 SBBI® Yearbook minus the arithmetic mean monthly yield of Moody's average Aaa and Aa corporate bonds from 1928-2021.
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2021 referenced in Note 1 above.
(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The SBBI equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between SBBI large company common stock monthly returns and average Aaa and Aa2 corporate monthly bond yields, from January 1928 through December 2022.
(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.05% (from page 3 of this Schedule) from the projected 3-5 year total annual market return of 16.58% (described fully in note 1 on page 2 of Schedule DWD-4).
(5) Using data from Value Line for the S&P 500, an expected total return of 15.67% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.05% results in an expected equity risk premium of 10.62%.
(6) Using data from Bloomberg for the S&P 500, an expected total return of 11.06% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.05% results in an expected equity risk premium of 6.01%.
(7) Average of mean and median beta from Schedule DWD-4.

Sources of Information:

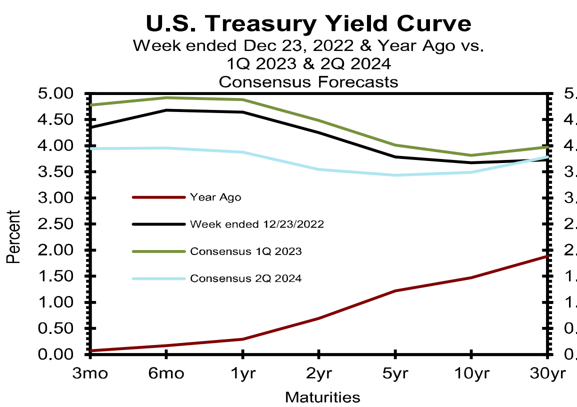
Stocks, Bonds, Bills, and Inflation - 2022 SBBI Yearbook, Kroll, Inc.
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index.
Blue Chip Financial Forecasts, January 1, 2023 and December 2, 2022
Bloomberg Professional Services.

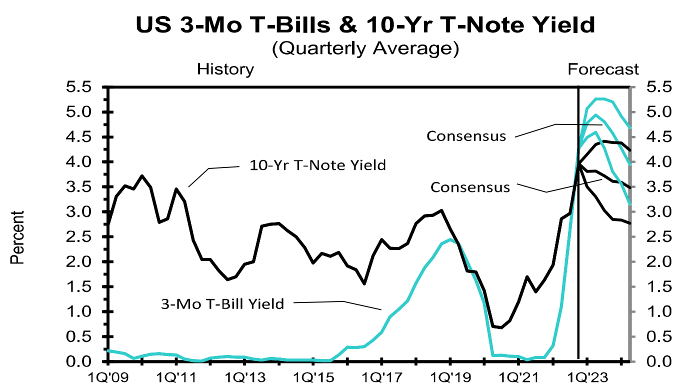
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

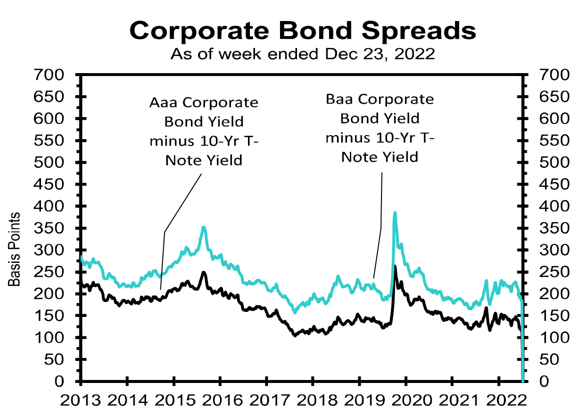
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	1Q	2Q	3Q	4Q	1Q	2Q
Interest Rates	Dec 23	Dec 16	Dec 9	Dec 2	Nov	Oct	Sep	4Q 2022*	**2023**	**2023**	**2023**	**2023**	**2024**	**2024**
Federal Funds Rate	4.33	3.83	3.83	3.83	3.78	3.08	2.56	3.59	**4.7**	**5.0**	**4.9**	**4.7**	**4.4**	**4.0**
Prime Rate	7.50	7.00	7.00	7.00	6.95	6.25	5.73	6.76	**7.8**	**8.1**	**8.0**	**7.8**	**7.5**	**7.2**
SOFR	4.30	4.01	3.80	3.81	3.73	3.04	2.50	3.55	**4.6**	**4.9**	**4.8**	**4.6**	**4.4**	**4.1**
Commercial Paper, 1-mo.	4.28	4.23	4.15	4.00	3.88	3.28	2.80	3.71	**4.8**	**5.1**	**4.9**	**4.6**	**4.4**	**4.0**
Treasury bill, 3-mo.	4.35	4.34	4.32	4.37	4.32	3.87	3.22	4.17	**4.8**	**4.9**	**4.8**	**4.6**	**4.3**	**3.9**
Treasury bill, 6-mo.	4.68	4.71	4.72	4.69	4.61	4.31	3.71	4.53	**4.9**	**5.0**	**4.8**	**4.5**	**4.3**	**4.0**
Treasury bill, 1 yr.	4.64	4.66	4.72	4.73	4.73	4.43	3.89	4.61	**4.9**	**4.9**	**4.7**	**4.4**	**4.2**	**3.9**
Treasury note, 2 yr.	4.25	4.25	4.33	4.37	4.50	4.38	3.86	4.39	**4.5**	**4.4**	**4.2**	**3.9**	**3.8**	**3.5**
Treasury note, 5 yr.	3.78	3.67	3.72	3.79	4.06	4.18	3.70	4.00	**4.0**	**4.0**	**3.9**	**3.7**	**3.6**	**3.4**
Treasury note, 10 yr.	3.67	3.51	3.52	3.63	3.89	3.98	3.52	3.82	**3.8**	**3.8**	**3.7**	**3.6**	**3.6**	**3.5**
Treasury note, 30 yr.	3.73	3.53	3.51	3.71	4.00	4.04	3.56	3.89	**4.0**	**4.0**	**3.9**	**3.9**	**3.8**	**3.8**
Corporate Aaa bond	4.88	4.66	4.68	4.87	5.23	5.41	4.87	5.15	**5.1**	**5.2**	**5.2**	**5.1**	**4.9**	**4.8**
Corporate Baa bond	5.56	5.34	5.38	5.57	5.95	6.22	5.64	5.90	**6.1**	**6.3**	**6.2**	**6.1**	**5.9**	**5.8**
State & Local bonds	4.24	4.18	4.19	4.26	4.50	4.62	4.31	4.46	**4.3**	**4.4**	**4.3**	**4.3**	**4.3**	**4.2**
Home mortgage rate	6.27	6.31	6.33	6.49	6.81	6.90	6.11	6.69	**6.5**	**6.5**	**6.3**	**6.2**	**6.0**	**5.8**

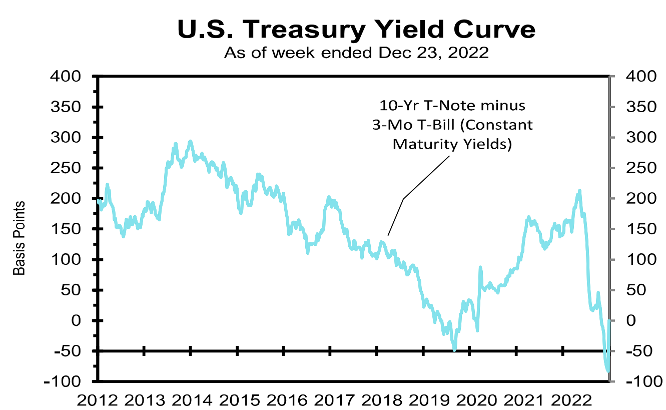
	History								Consensus Forecasts-Quarterly					
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	**1Q**	**2Q**	**3Q**	**4Q**	**1Q**	**2Q**
Key Assumptions	2021	2021	2021	2021	2022	2022	2022	2022**	**2023**	**2023**	**2023**	**2023**	**2024**	**2024**
Fed's AFE $ Index	103.4	102.9	105.0	107.0	108.4	113.7	119.0	120.6	**118.7**	**118.1**	**117.6**	**117.1**	**116.8**	**116.9**
Real GDP	6.3	7.0	2.7	7.0	-1.6	-0.6	3.2	1.0	**-0.2**	**-0.7**	**0.3**	**0.9**	**1.3**	**1.7**
GDP Price Index	5.2	6.3	6.2	6.8	8.3	9.0	4.4	4.3	**3.6**	**3.0**	**2.7**	**2.5**	**2.3**	**2.2**
Consumer Price Index	4.1	8.2	6.7	7.9	9.2	10.5	5.7	4.5	**3.4**	**3.1**	**2.9**	**2.6**	**2.4**	**2.3**
PCE Price Index	4.5	6.4	5.6	6.2	7.5	7.3	4.3	4.2	**3.2**	**2.8**	**2.6**	**2.5**	**2.4**	**2.2**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. *Interest rate data for 4Q 2022 based on historical data through the week ended December 23. **Data for 4Q 2022 for the Fed's AFE $ Index based on data through the week ended December 23. Figures for 4Q 2022 Real GDP, GDP Chained Price Index, Consumer Price Index, and PCE Price Index are consensus forecasts from the December 2022 survey.









Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2024 through 2028 and averages for the five-year periods 2024-2028 and 2029-2033. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

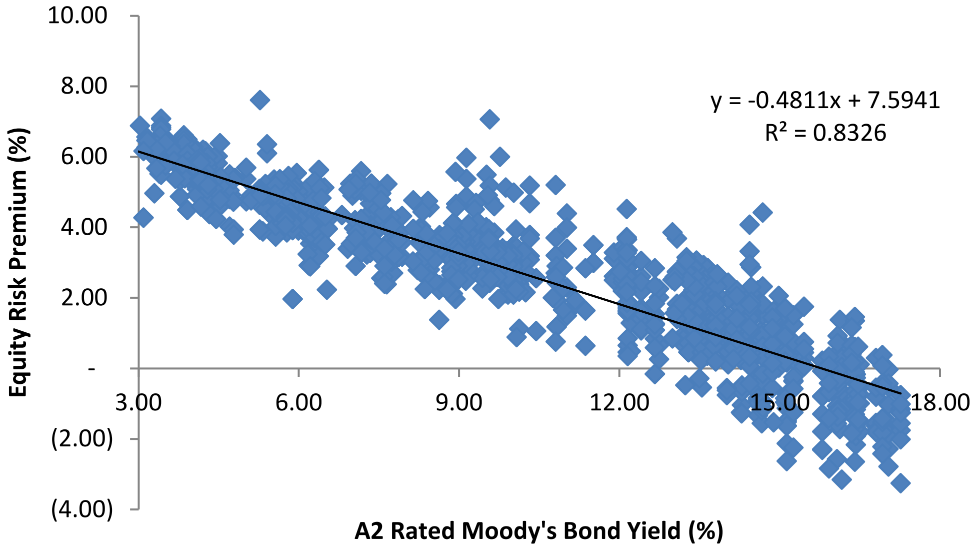
		Average For The Year					Five-Year Averages	
		2024	2025	2026	2027	2028	2024-2028	2029-2033
1. Federal Funds Rate	**CONSENSUS**	**3.7**	**2.9**	**2.8**	**2.8**	**2.7**	**3.0**	**2.8**
	Top 10 Average	4.5	3.7	3.6	3.5	3.4	3.7	3.4
	Bottom 10 Average	2.7	2.2	2.2	2.2	2.2	2.3	2.3
2. Prime Rate	**CONSENSUS**	**6.8**	**6.1**	**5.9**	**5.9**	**5.9**	**6.1**	**5.9**
	Top 10 Average	7.6	6.8	6.7	6.6	6.5	6.8	6.5
	Bottom 10 Average	5.9	5.3	5.3	5.3	5.3	5.4	5.3
3. SOFR	**CONSENSUS**	**3.7**	**2.9**	**2.8**	**2.8**	**2.7**	**3.0**	**2.8**
	Top 10 Average	4.4	3.6	3.4	3.3	3.2	3.6	3.3
	Bottom 10 Average	3.0	2.3	2.2	2.2	2.2	2.4	2.2
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.7**	**3.1**	**3.0**	**2.9**	**2.9**	**3.1**	**2.9**
	Top 10 Average	4.4	3.6	3.5	3.4	3.3	3.6	3.3
	Bottom 10 Average	3.2	2.6	2.5	2.4	2.4	2.6	2.5
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.7**	**3.0**	**2.9**	**2.8**	**2.8**	**3.0**	**2.8**
	Top 10 Average	4.4	3.7	3.6	3.5	3.4	3.7	3.4
	Bottom 10 Average	2.9	2.2	2.3	2.2	2.2	2.4	2.3
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.7**	**3.0**	**3.0**	**3.0**	**2.9**	**3.1**	**3.0**
	Top 10 Average	4.4	3.7	3.7	3.6	3.5	3.8	3.5
	Bottom 10 Average	3.1	2.4	2.4	2.4	2.4	2.5	2.4
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.8**	**3.1**	**3.1**	**3.1**	**3.0**	**3.2**	**3.1**
	Top 10 Average	4.4	3.8	3.7	3.6	3.5	3.8	3.6
	Bottom 10 Average	3.1	2.5	2.5	2.5	2.5	2.6	2.6
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.6**	**3.2**	**3.2**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	4.4	3.9	3.8	3.8	3.7	3.9	3.8
	Bottom 10 Average	2.7	2.5	2.6	2.6	2.6	2.6	2.6
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.6**	**3.3**	**3.4**	**3.4**	**3.3**	**3.4**	**3.4**
	Top 10 Average	4.4	4.0	4.0	4.0	3.9	4.1	3.9
	Bottom 10 Average	2.9	2.7	2.7	2.8	2.8	2.8	2.9
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**3.7**	**3.5**	**3.6**	**3.6**	**3.6**	**3.6**	**3.7**
	Top 10 Average	4.4	4.2	4.4	4.4	4.3	4.3	4.3
	Bottom 10 Average	3.0	2.9	2.8	2.9	3.0	2.9	3.0
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.0**	**3.9**	**3.9**	**4.0**	**3.9**	**3.9**	**4.0**
	Top 10 Average	4.6	4.5	4.7	4.6	4.6	4.6	4.7
	Bottom 10 Average	3.4	3.3	3.3	3.3	3.3	3.3	3.3
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.1**	**4.9**	**5.0**	**5.0**	**5.0**	**5.0**	**5.1**
	Top 10 Average	5.7	5.5	5.6	5.6	5.6	5.6	5.7
	Bottom 10 Average	4.6	4.4	4.4	4.4	4.5	4.4	4.5
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.2**	**5.9**	**5.9**	**6.0**	**5.9**	**6.0**	**6.0**
	Top 10 Average	6.6	6.4	6.5	6.5	6.5	6.5	6.6
	Bottom 10 Average	5.7	5.3	5.3	5.4	5.4	5.4	5.5
14. State & Local Bonds Yield	**CONSENSUS**	**4.4**	**4.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.4**
	Top 10 Average	4.8	4.7	4.8	4.7	4.7	4.7	4.8
	Bottom 10 Average	3.9	3.7	3.8	3.9	3.9	3.9	3.9
15. Home Mortgage Rate	**CONSENSUS**	**5.9**	**5.5**	**5.5**	**5.5**	**5.5**	**5.6**	**5.5**
	Top 10 Average	6.6	6.2	6.2	6.2	6.2	6.3	6.2
	Bottom 10 Average	5.3	4.8	4.8	4.8	4.8	4.9	4.9
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**117.6**	**116.0**	**114.5**	**113.5**	**112.2**	**114.8**	**110.7**
	Top 10 Average	120.7	119.3	118.5	118.0	117.9	118.9	116.7
	Bottom 10 Average	115.1	112.9	110.7	109.2	107.2	111.0	105.4
		Year-Over-Year, % Change					**Five-Year Averages**	
		2024	**2025**	**2026**	**2027**	**2028**	**2024-2028**	**2029-2033**
B. Real GDP	**CONSENSUS**	**1.4**	**2.2**	**2.1**	**2.0**	**2.0**	**1.9**	**1.9**
	Top 10 Average	2.2	2.6	2.6	2.4	2.4	2.5	2.3
	Bottom 10 Average	0.5	1.8	1.7	1.7	1.7	1.5	1.6
C. GDP Chained Price Index	**CONSENSUS**	**2.3**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.7	2.4	2.3	2.3	2.3	2.4	2.2
	Bottom 10 Average	2.0	1.9	1.9	1.9	1.9	1.9	1.9
D. Consumer Price Index	**CONSENSUS**	**2.4**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.1**
	Top 10 Average	2.8	2.5	2.4	2.3	2.3	2.5	2.3
	Bottom 10 Average	2.0	2.0	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	**CONSENSUS**	**2.3**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.6	2.4	2.4	2.3	2.2	2.4	2.2
	Bottom 10 Average	1.9	1.9	1.9	1.9	2.0	1.9	1.9

The Potomac Edison Company
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.	Equity Risk Premium based on S&P Utility Index Holding Period Returns (1) :	Implied Equity Risk Premium
1.	Historical Equity Risk Premium	4.28 %
2.	Regression of Historical Equity Risk Premium (2)	4.80
3.	Forecasted Equity Risk Premium Based on PRPM (3)	5.56
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Value Line Data) (4)	3.62
5.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg Data) (5)	3.32
6.	Average Equity Risk Premium (6)	4.32 %

Notes:
(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2021. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2021 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the relevant bond yield. The projected A2 rated utiliy bond yields are shown on line 3 of page 3 of this Schedule.
(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - December 2022.
(4) Using data from Value Line for the S&P Utilities Index, an expected return of 9.50% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.88%, calculated on line 3 of page 3 of this Schedule results in an equity risk premium of 3.62%. (9.50% - 5.88% = 3.62%)
(5) Using data from Bloomberg Professional Services for the S&P Utilities Index, an expected return of 9.20% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.88%, calculated on line 3 of page 3 of this Schedule results in an equity risk premium of 3.32%. (9.20% - 5.88% = 3.32%)
(6) Average of lines 1 through 5.

The Potomac Edison Company
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Electric Utilities



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.5941 %	-0.4811	5.88 %	4.77 %

Notes:
(1) From line 3 of page 3 of this Schedule.

Source of Information: Regulatory Research Associates.

The Potomac Edison Company
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Thirteen Electric Utilities	[1] Value Line Adjusted Beta	[2] Bloomberg Adjusted Beta	[3] Average Beta	[4] Market Risk Premium (1)	[5] Risk-Free Rate (2)	[6] Traditional CAPM Cost Rate	[7] ECAPM Cost Rate	[8] Indicated Common Equity Cost Rate (3)
Alliant Energy Corporation	0.85	0.72	0.78	9.75 %	3.91 %	11.51 %	12.05 %	11.78 %
Ameren Corporation	0.85	0.74	0.79	9.75	3.91	11.61	12.12	11.87
American Electric Power Corporation	0.75	0.66	0.71	9.75	3.91	10.83	11.54	11.19
Duke Energy Corporation	0.85	0.63	0.74	9.75	3.91	11.12	11.76	11.44
Edison International	0.95	0.83	0.89	9.75	3.91	12.59	12.86	12.72
Entergy Corporation	0.95	0.73	0.84	9.75	3.91	12.10	12.49	12.29
Evergy, Inc.	0.90	0.68	0.79	9.75	3.91	11.61	12.12	11.87
Eversource Energy	0.90	0.69	0.80	9.75	3.91	11.71	12.20	11.95
IDACORP, Inc.	0.80	0.63	0.72	9.75	3.91	10.93	11.61	11.27
NorthWestern Corporation	0.90	0.61	0.75	9.75	3.91	11.22	11.83	11.53
OGE Energy Corporation	1.00	0.75	0.88	9.75	3.91	12.49	12.78	12.64
Portland General Electric Company	0.85	0.63	0.74	9.75	3.91	11.12	11.76	11.44
Xcel Energy Inc.	0.80	0.68	0.74	9.75	3.91	11.12	11.76	11.44
Mean			0.78			11.54 %	12.07 %	11.80 %
Median			0.78			11.51 %	12.05 %	11.78 %
Average of Mean and Median			0.78			11.53	12.06	11.79 %

Notes on page 2 of this Schedule.

The Potomac Edison Company
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using six different measures from three sources: Kroll, Value Line, and Bloomberg as illustrated below:

Historical Data MRP Estimates:

Measure 1: Kroll Arithmetic Mean MRP (1926-2021)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2021:	12.37	%
Arithmetic Mean Income Returns on Long-Term Government Bonds:	5.02	
MRP based on Kroll Historical Data:	7.35	%

Measure 2: Application of a Regression Analysis to Kroll Historical Data (1926-2022)	8.71	%

Measure 3: Application of the PRPM to Kroll Historical Data: (January 1926 - December 2022)	10.86	%

Value Line MRP Estimates:

Measure 4: Value Line Projected MRP (Thirteen weeks ending December 30, 2022)

Total projected return on the market 3-5 years hence*:	16.58	%
Projected Risk-Free Rate (see note 2):	3.91	
MRP based on Value Line Summary & Index:	12.67	%

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Value Line Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	15.67	%
Projected Risk-Free Rate (see note 2):	3.91	
MRP based on Value Line data	11.76	%

Measure 6: Bloomberg Projected MRP

Total return on the Market based on the S&P 500:	11.06	%
Projected Risk-Free Rate (see note 2):	3.91	
MRP based on Bloomberg data	7.15	%
Average of Value Line, Kroll, and Bloomberg MRP:	9.75	%

(2) For reasons explained in the direct testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 10-11 of Schedule DWD-3.) The projection of the risk-free rate is illustrated below:

First Quarter 2023	4.00	%
Second Quarter 2023	4.00	
Third Quarter 2023	3.90	
Fourth Quarter 2023	3.90	
First Quarter 2024	3.80	
Second Quarter 2024	3.80	
2024-2028	3.90	
2029-2033	4.00	
	3.91	%

(3) Average of Column 6 and Column 7.

Sources of Information:

Value Line Summary and Index
Blue Chip Financial Forecasts, January 1, 2023 and December 2, 2022
Stocks, Bonds, Bills, and Inflation - 2022 SBBI Yearbook, Kroll, Inc.
Bloomberg Professional Services

The Potomac Edison Company
Basis of Selection of the Groups of Non-Price Regulated Companies
Comparable in Total Risk to the Utility Proxy Groups

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the Utility Proxy Group was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.65 – 0.93 and residual standard error of the regression range of 2.5574 – 3.0502 of the Proxy Group of Thirteen Electric Utilities.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Electric Utility Proxy Group's residual standard error of the regression is 0.1232. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus, } 0.1232 = \frac{2.8038}{\sqrt{518}} = \frac{2.8038}{22.7596}$$

Source of Information: Value Line, Inc., December 2022.
Value Line Investment Survey (Standard Edition).

The Potomac Edison Company
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

	[1]	[2]	[3]	[4]
Proxy Group of Thirteen Electric Utilities	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Alliant Energy Corporation	0.85	0.71	2.7441	0.0683
Ameren Corporation	0.80	0.69	2.5700	0.0640
American Electric Power Corporation	0.75	0.59	2.6606	0.0662
Duke Energy Corporation	0.85	0.76	2.7262	0.0679
Edison International	0.95	0.91	3.2762	0.0816
Entergy Corporation	0.95	0.86	2.7816	0.0692
Evergy, Inc.	0.95	0.87	3.1310	0.0806
Eversource Energy	0.90	0.83	3.0490	0.0759
IDACORP, Inc.	0.80	0.68	2.5804	0.0642
NorthWestern Corporation	0.95	0.89	2.7689	0.0689
OGE Energy Corporation	1.05	1.05	2.6629	0.0663
Portland General Electric Company	0.90	0.79	2.8012	0.0697
Xcel Energy Inc.	0.80	0.66	2.6976	0.0672
Average	0.88	0.79	2.8038	0.0700

Beta Range (+/- 2 std. Devs. of Beta)	0.65	0.93
2 std. Devs. of Beta	0.14	
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.5574	3.0502
Std. dev. of the Res. Std. Err.	0.1232	
2 std. devs. of the Res. Std. Err.	0.2464	

Source of Information: Value Line Proprietary Database, December 2022

The Potomac Edison Company
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Thirteen Electric Utilities

Proxy Group of Fifty Non-Price Regulated Companies	[1] VL Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Agilent Technologies	0.85	0.77	2.6442	0.0658
Abbott Labs.	0.90	0.81	2.7622	0.0688
Analog Devices	0.95	0.87	2.8417	0.0707
Assurant Inc.	0.95	0.85	2.7366	0.0681
Smith (A.O.)	0.85	0.76	2.7272	0.0679
Air Products & Chem.	0.90	0.79	2.6237	0.0653
Ball Corp.	0.95	0.91	2.8314	0.0705
Brown-Forman 'B'	0.90	0.80	2.6915	0.0670
Bristol-Myers Squibb	0.85	0.76	3.0330	0.0755
Broadridge Fin'l	0.85	0.70	2.7610	0.0687
Brady Corp.	1.00	0.93	2.7641	0.0688
CACI Int'l	0.90	0.84	2.9846	0.0743
Chemed Corp.	0.85	0.70	2.7215	0.0677
Cooper Cos.	0.95	0.90	2.7720	0.0690
CSW Industrials	0.90	0.80	2.9127	0.0725
Quest Diagnostics	0.80	0.69	3.0218	0.0752
Dolby Labs.	0.95	0.88	2.6152	0.0651
Lauder (Estee)	0.95	0.92	2.9395	0.0732
Exponent, Inc.	0.90	0.80	2.8742	0.0715
FactSet Research	1.00	0.93	2.6951	0.0671
Gentex Corp.	0.95	0.90	2.7524	0.0685
Ingredion Inc.	0.90	0.85	2.8617	0.0712
Hunt (J.B.)	0.95	0.90	2.9072	0.0724
J&J Snack Foods	0.95	0.87	2.9766	0.0741
Henry (Jack) & Assoc	0.85	0.70	2.8821	0.0717
L3Harris Technologie	0.95	0.92	2.5815	0.0709
McCormick & Co.	0.80	0.66	2.8331	0.0705
Altria Group	0.95	0.88	2.9551	0.0736
MSA Safety	0.95	0.92	3.0013	0.0747
MSCI Inc.	0.95	0.85	3.0171	0.0751
Motorola Solutions	0.90	0.79	2.6757	0.0666
Mettler-Toledo Int'l	0.95	0.89	2.7628	0.0688
Northrop Grumman	0.85	0.74	2.9186	0.0727
Old Dominion Freight	0.95	0.85	2.9677	0.0739
Packaging Corp.	0.95	0.90	2.8815	0.0717
Post Holdings	0.95	0.86	2.9244	0.0728
RLI Corp.	0.80	0.66	2.8575	0.0711
Rollins, Inc.	0.85	0.72	2.9831	0.0743
Service Corp. Int'l	0.95	0.89	2.6275	0.0654
Sherwin-Williams	0.90	0.84	2.5643	0.0638
Selective Ins. Group	0.90	0.81	2.9464	0.0733
Sirius XM Holdings	0.95	0.86	2.9589	0.0737
Sensient Techn.	0.90	0.82	2.6393	0.0657
Thermo Fisher Sci.	0.85	0.70	2.6279	0.0654
Texas Instruments	0.85	0.75	2.6590	0.0662
U-Haul Holding	0.95	0.92	2.7274	0.0679
UniFirst Corp.	0.95	0.91	2.7167	0.0676
VeriSign Inc.	0.90	0.78	2.5863	0.0644
Waters Corp.	0.95	0.87	2.8032	0.0698
Watsco, Inc.	0.85	0.75	2.6936	0.0671
Average	0.91	0.82	2.8049	0.0700
Proxy Group of Thirteen Electric Utilities	0.88	0.79	2.8038	0.0700

Source of Information: Value Line Proprietary Database, December 2022

FINANCIAL QUARTERLY
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Comparable Earnings: New Life for an Old Precept

by
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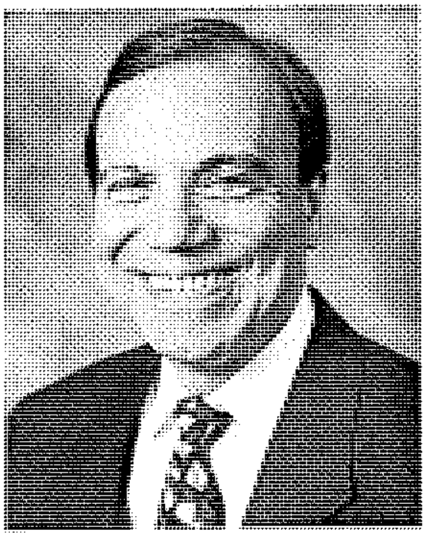
Comparable Earnings: New Life for an Old Precept



Accelerating deregulation has greatly increased the investment risk of natural gas utilities. As a result, the authors believe it more appropriate than ever to employ the comparable earnings model. We believe our application of the model overcomes the greatest traditional objection to it — lack of comparability of the selected non-utility proxy firms. Our illustration focuses on a target gas pipeline company with a beta of 0.96 — almost equal to the market's beta of 1.00.

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Introduction

The comparable earnings model used to determine a common equity cost rate is deeply rooted in the standard of "corresponding risk" enunciated in the landmark *Bluefield* and *Hope* decisions of the U.S. Supreme Court.[1] With such solid grounding in the foundations of rate of return regulation, comparable earnings should be accepted as a principal model, along with the currently popular market-based models, provided that its most common criticism, non-comparability of the proxy companies, is overcome.

Our comparable earnings model overcomes the non-comparability issue of the non-utility firms selected as a proxy for the target utility, in this example, a gas pipeline company. We should note that in the absence of common stock prices for the target utility (as with a wholly-owned subsidiary), it is appropriate to use the average of a proxy group of similar risk gas pipeline companies whose common stocks are actively traded. As we will demonstrate, our selection process results in a group of domestic, non-utility firms that is comparable in total risk, the sum of business and financial risk, which reflects both non-diversifiable systematic, or market, risk as well as diversifiable unsystematic, or firm-specific, risk.

Embedded in the Landmark Decisions

As stated in *Bluefield* in 1922: "A public utility is entitled to such rates as will permit it to earn a return ... on investments in other business undertakings which are attended by corresponding risks and uncertainties ..."

In addition, the court stated in *Hope* in 1944: "By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

Thus, the "corresponding risk" precept of *Bluefield* and *Hope* predates the use of such market-based cost-of-equity models as the Discounted Cash Flow (DCF) and Capital Asset Pricing (CAPM), which were developed later and are currently popular in rate-base/rate-of-return regulation. Consequently, the comparable earnings model has a longer regulatory and judicial history. However, it has far greater relevance now than ever before in its history because significant deregulation has substantially increased natural gas utilities' investment risk to a level similar to that of non-utility firms. As a result, it is

Comparable Earnings *from page 4*

more important than ever to look to similar-risk non-utility firms for insight into common equity cost rate, especially in view of the deficiencies inherent in the currently popular market-based cost of common equity models, particularly the DCF model.

Despite the fact that the landmark decisions are still regarded as having set the standards for determining a fair rate of return, the comparable earnings model has experienced decreased usage by expert witnesses, as well as less regulatory acceptance over the years. We believe the decline in the popularity of the comparable earnings model, in large measure, is attributable to the difficulty of selecting non-utility proxy firms that regulators will accept as comparable to the target utility. Regulatory acceptance is difficult to gain when the selection process is arbitrary. Our application of the model is objective and consistent with fundamental financial tenets.

Principles of Comparable Earnings

Regulation is a substitute for the competition of the marketplace. Moreover, regulated public utilities compete in the capital markets with all firms, including unregulated non-utilities. The comparable earnings model is based upon the opportunity cost principle; i.e., that the true cost of an investment is the return that could have been earned on the next best available alternative investment of similar risk. Consequently, the comparable earnings model is consistent with regulatory and financial principles, as it is a surrogate for the competition of the marketplace, and investors seek the greatest available rate of return for bearing similar risk.

The selection of comparable firms is the most difficult step in applying the comparable earnings model, as noted by Phillips[2] as well as by Bonbright, Danielsen and Kamerschen.[3] The selection of non-utility proxy firms should result in a sufficiently broad-based group in order to minimize the effect of company-specific aberrations. However, if the selection process is arbitrary, it likely would result in a proxy group that is too broad-based, such as the Standard & Poor's 500 Composite Index or the Value Line Industrial Composite. The use of such groups would require subjective adjustments to the comparable earnings results to reflect risk differences between the group(s) and the target utility, a gas pipeline company in this example.

Authors' Selection Criteria

We base the selection of comparable non-utility firms on market-based, objective, quantitative measures of risk resulting from market prices that subsume investors' assessments of all elements of risk. Thus, our approach is based upon the principle of risk and return; namely, that firms of comparable risk should be expected to earn comparable returns. It is also consistent with the "corresponding risk" standard established in *Bluefield* and *Hope*. We measure total investment risk as the sum of non-diversifiable systematic and diversifiable unsystematic risk. We use the unadjusted beta as a measure of systematic risk and the standard error of the estimate (residual standard error) as a measure of unsystematic risk. Both the unadjusted beta and the residual standard error are derived from a regression of the target utility's security returns relative to the market's returns, which takes the general form:

$$r_{it} = a_i + b_i\, r_{mt} + e_{it}$$

where:

r_{it} = tth observation of the ith utility's rate of return

r_{mt} = tth observation of the market's rate of return

e_{it} = tth random error term

a_i = constant least-squares regression coefficient

b_i = least-squares regression slope coefficient, the unadjusted beta.

As shown by Francis,[4] the total variation or risk of a firm's return, Var (r_i), comes from two sources:

Var (r_i) = total risk of ith asset

= $\mathrm{var}(a_i + b_i r_m + e)$ substituting $(a_i + b_i r_m + e)$ for r_i

= $\mathrm{var}(b_i r_m)$ + var (e) since $\mathrm{var}(a_i) = 0$

= $b_i^2\,\mathrm{var}(r_m)$ + var (e) since $\mathrm{var}(b_i r_m) = b_i^2\,\mathrm{var}(r_m)$

= systematic + unsystematic risk

Francis[5] also notes: "The term $\sigma^2(r_i|r_m)$ is called the *residual variance around the regression line* in statistical terms or *unsystematic risk* in capital market theory language. $\sigma^2(r_i|r_m) = \ldots = \mathrm{var}(e)$. The residual variance is the squared standard error in regression language, a measure of unsystematic risk." Application of these criteria results in a group of non-utility firms whose average total investment risk is indeed comparable to that of the target gas pipeline.

As a measure of systematic risk, we use the Value Line unadjusted beta. Beta measures the extent to which market-wide or macro-economic events affect a firm's stock price. We use the unadjusted beta of the target utility as a starting point because it results from the regression of the target utility's security returns relative to the market's returns. Thus, the resulting standard deviation of beta relates to the unadjusted beta. We use the standard deviation of the unadjusted beta to determine the range around it as the selection criterion based on systematic risk.

We use the residual standard error of the regression as a measure of unsystematic risk. The residual standard error reflects the extent to which events specific to the firm's operations affect a firm's stock price. Thus, it is a measure of diversifiable, unsystematic, firm-specific risk.

An Illustration of Authors' Approach

Step One: We begin our approach by establishing the selection criteria as a range of both unadjusted beta and residual standard error of the target gas

continued on page 6

Comparable Earnings *from page 5*

from page 5

pipeline company.

As shown in table 1, our target gas pipeline company has a Value Line unadjusted beta of 0.90, whose standard deviation is 0.1250. The selection criterion range of unadjusted beta is the unadjusted beta plus (+) and minus (-) three of its standard deviations. By using three standard deviations, 99.73 percent of the comparable unadjusted betas is captured.

Three standard deviations of the target utility's unadjusted beta equals 0.38 (0.1250 x 3 = 0.3750, rounded to 0.38). Consequently, the range of unadjusted betas to be used as a selection criteria is 0.52 - 1.28 (0.52 = 0.90 - 0.38) and (1.28 = 0.90 + 0.38).

Likewise, the selection criterion range of residual standard error equals the residual standard error plus (+) and minus (-) three of its standard deviations. The standard deviation of the residual standard error is defined as: $\sigma/\sqrt{2N}$.

As also shown in table 1, the target gas pipeline company has a residual standard error of 3.7867. According to the above formula, the standard deviation of the residual standard error would be 0.1664 (0.1664 = $3.7867/\sqrt{2(259)}$ = 3.7867/22.7596, where 259 = N, the number of weekly price change observations over a period of five years). Three standard deviations of the target utility's residual standard error would be 0.4992 (0.1664 x 3 = .4992). Consequently, the range of residual standard errors to be used as a selection criterion is 3.2875 - 4.2859 (3.2875 = 3.7867 - 0.4992) and (4.2859 = 3.7867 + 0.4992).

Step Two: The step one criteria are applied to Value Line's data base of nearly 4,000 firms for which Value Line derives unadjusted betas and residual standard errors on a weekly basis. All firms with unadjusted betas and residual standard errors within the criteria ranges are then selected.

Step Three: In the regulatory ratemaking environment, authorized common equity return rates are applied to a book-value rate base. Thus, the earnings rates on book common equity, or net worth, of competitive, non-utility firms are highly relevant provided those firms are indeed comparable in total risk to the target gas pipeline. The use of the return rates of other utilities has no relevance because their allowed, and hence subsequently achieved, earnings rates are dependent upon the regulatory

table 1

Summary of the Comparable Earnings Analysis for the Proxy Group of 248 Non-Utility Companies Comparable in Total Risk to the Target Gas Pipeline Company[1]

	1	2	3	4	5	6	7	8
			residual	rate of return on net worth				
	adj. beta	unadj. beta	standard error	3-year average[2]	4-year average[2]	5-year average[2]	5-year projected[3]	
average for the proxy group of 248 non-utility companies comparable in total risk to the target gas pipeline company	0.97	0.92	3.7705					
target gas pipeline company	0.96	0.90[4]	3.7867					
median				11.7%	12.0%	12.6%	15.5%	
average of the median historical returns					12.1%			
conclusion[5]								13.8%

[1]The criteria for selection of the non-utility group was that the non-utility companies be domestic and included in *Value Line Investment Survey*. The non-utility group was selected based on an unadjusted beta range of 0.52 to 1.28 and a residual standard error range of 3.2875 to 4.2859.
[2]Ending 1992.
[3]1996-1998/1997-1999.
[4]The average standard deviation of the target gas pipeline company's unadjusted beta is 0.1250.
[5]Equal weight given to both the average of the 3-, 4- and 5-year historical medians (12.1%) and 5-year projected median rate of return on net worth (15.5%). Thus, 13.8% = (12.1% + 15.5% / 2).
Source: Value Line Inc., March 15, 1994
Value Line Investment Survey

Comparable Earnings *from page 6*

process. Consequently, we believe all utilities must be eliminated to avoid circularity. Moreover, we believe non-domestic firms must be eliminated because their reporting methods differ significantly from U.S. firms.

Step Four: We then eliminated those firms for which Value Line does not publish a "Ratings & Report" in *Value Line Investment Survey* so that the historical and projected returns on net worth[6] are from a consistent source. We use historical returns on net worth for the most recent five years, as well as those projected three to five years into the future. We believe it is logical to evaluate both historical and projected return rates because it is reasonable to assume that investors avail themselves of both when they are available from widely disseminated information services, such as Value Line Inc. The use of Value Line's return rates on net worth understates the common equity return rates for two reasons. First, preferred stock is included in net worth. Second, the net worth return rates are as of the end of each period. Thus, the use of average common equity return rates would yield higher results.

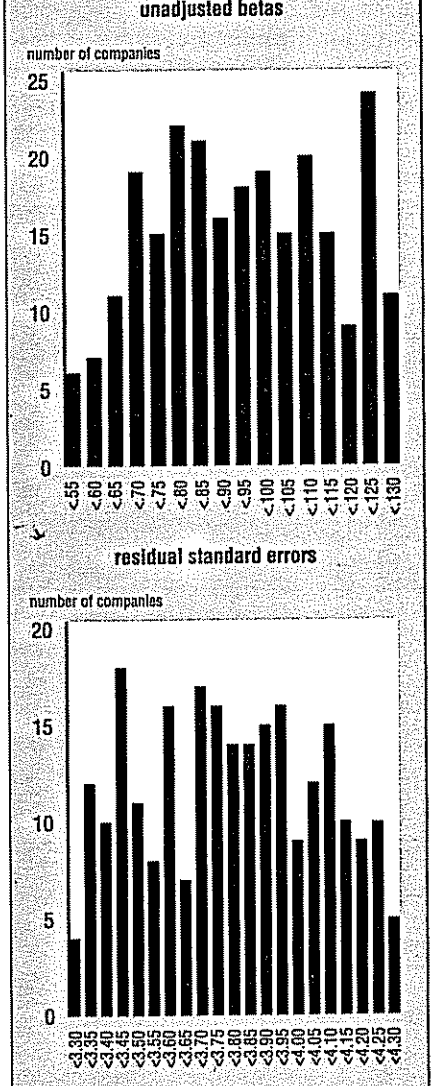
Step Five: Median returns based on the historical average three, four and five years ending 1992 and projected 1996-1998 or 1997-1999 rates of return on net worth are then determined as shown in columns 4 through 7 of table 1. The median is used due to the wide variations and skewness in rates of return on net worth for the non-utility firms as evidenced by the frequency distributions of those returns as shown in illustration 1.

However, we show the average unadjusted beta, 0.92, and residual standard error, 3.7705, for the proxy group in columns 2 and 3 of table 1 because their frequency distributions are not significantly skewed, as shown in illustration 2.

Step Six: Our conclusion of a com-

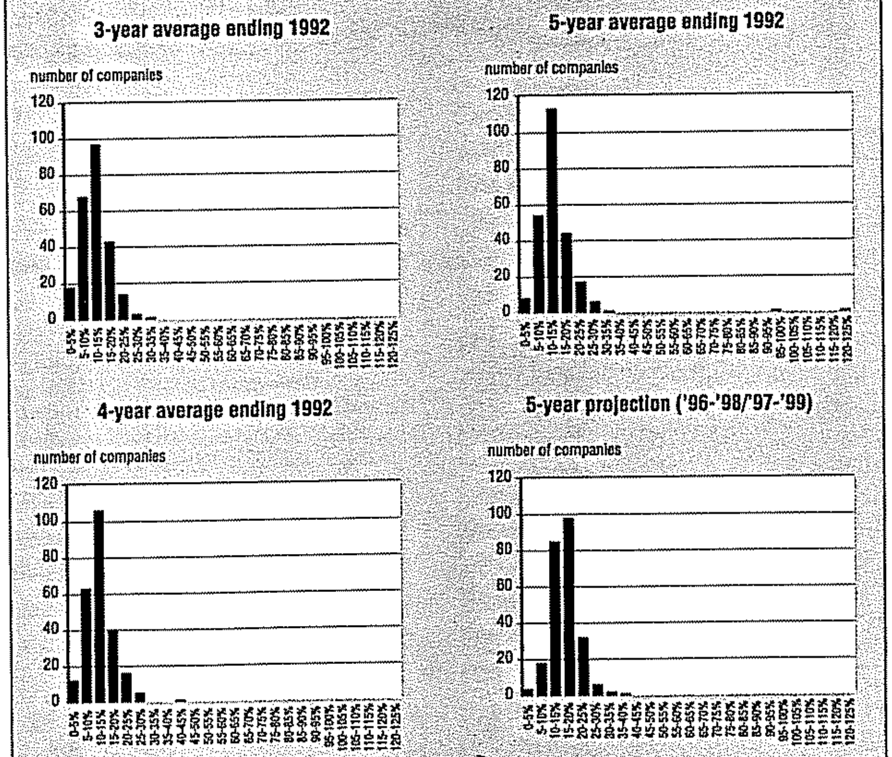
continued on page 8

Illustration 2
Unadjusted Betas and Residual Standard Errors for the Proxy Group of 248 Non-Utility Companies[1]



[1]Comparable to target gas pipeline

Illustration 1
Rates of Return on Net Worth for the Proxy Group of 248 Non-Utility Companies[1]



[1]Comparable to target gas pipeline

Comparable Earnings *from page 7*

parable earnings cost rate is based upon the mid-point of the average of the median three-, four- and five-year historical rates of return on net worth of 12.1 percent as shown in column 5 and the median projected 1996-1998/1997-1999 rate of return on net worth of 15.5 percent as shown in column 7 of table 1. As shown in column 8, it is 13.8 percent.

Summary

Our comparable earnings approach demonstrates that it is possible to select a proxy group of non-utility firms that is comparable in total risk to a target utility. In our example, the 13.8 percent comparable earnings cost rate is very conservative as it is an expected achieved rate on book common equity (a regulatory allowed rate should be greater) and because it is based on end-of-period net worth. A similar rate on average net worth would be about 20 to 40 basis points higher (i.e., 14.0 to 14.2 percent) and still understate the appropriate regulatory allowed rate of return on book common equity.

Our selection criteria are based upon measures of systematic and unsystematic risk, specifically unadjusted beta and residual standard error. They provide the basis for the objective selection of comparable non-utility firms. Our selection criteria rely on changes in market prices over approximately five years. We compare the aggregate total risk, or the sum of systematic and unsystematic risk, which reflects investors' aggregate assessment of both business and financial risk. Thus, no adjustments are necessary to the proxy group results to compensate for the differences in business risk and financial risk, such as accounting practices and debt/equity ratios. Moreover, it is inappropriate to attempt a comparison of the target utility with any individual firm, or subset of firms, in the proxy group because only the average firm of the group is relevant.

Because the comparable earnings model is firmly anchored in the "corresponding risk" precept established in the landmark court decisions, it is worthy of consideration as a principal model for use in estimating the cost rate of common equity capital of a regulated utility. Our approach to the comparable earnings model produces a proxy group that is indeed comparable in total risk because the selection process is objective and quantitative. It therefore overcomes criticism linked to arbitrary selection processes.

All cost-of-common-equity models, including the DCF and CAPM, are fraught with deficiencies, usually stemming from the many necessary but unrealistic assumptions that underlie them. The effects of the deficiencies of individual models can be mitigated by using more than one model when estimating a utility's common equity cost rate. Therefore, when the non-comparability issue is overcome, the comparable earnings model deserves to receive the same consideration as a primary model, as do the currently popular market-based models. ■

[1] *Bluefield Water Works Improvement Co. v. Public Service Commission*. 262 U.S. 679 (1922) and *Federal Power Commission v. Hope Natural Gas Co*. 320 U.S. 519 (1944).
[2] Charles F. Phillips Jr., The Regulation of Public Utilities: Theory and Practice. Public Utilities Reports Inc., 1988, p. 379
[3] James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utilities Rates. 2nd edition. Public Utilities Reports Inc. 1988, p. 329.
[4] Jack Clark Francis, Investments: Analysis and Management, 3rd edition. McGraw-Hill Book Co., 1980, p. 363.
[5] Id., p. 548.
[6] Returns on net worth must be used when relying on Value Line data because returns on book common equity for non-utility firms are not available from Value Line

Report Lists Pipeline, Storage Projects

More than $9 billion worth of projects to expand the nation's natural gas pipeline network are in various stages of development, according to an A.G.A. report. These projects involve nearly 8,000 miles of new pipelines and capacity additions to existing lines and represent 15.3 billion cubic feet (Bcf) per day of new pipeline capacity.

During 1993 and early 1994, construction on 3,100 miles of pipeline was completed or under way, at a cost of nearly $4 billion, says A.G.A. These projects are adding 5.4 Bcf in daily delivery capacity nationwide.

Among the projects completed in 1993 were Pacific Gas Transmission Co.'s 805 miles of looping that allows increased deliveries of Canadian gas to the West Coast; Northwest Pipeline Corp.'s addition of 433 million cubic feet of daily capacity for customers in the Pacific Northwest and Rocky Mountain areas; and the 156-mile Empire State Pipeline in New York.

In addition, major construction projects were started on the systems of Texas Eastern Transmission Corp. and Algonquin Gas Transmission Co. — both subsidiaries of Panhandle Eastern Corp. — and along Florida Gas Transmission Co.'s pipeline.

The report goes on to discuss another $5 billion in proposed projects, which, if completed, will add nearly 5,000 miles of pipeline and 9.8 Bcf per day in capacity, much of it serving Florida and West Coast markets.

A.G.A. also identifies 47 storage projects and says that if all of them are built, existing storage capacity will increase by more than 500 Bcf, or 15 percent.

For a copy of *New Pipeline Construction: Status Report 1993-94* (#F00103), call A.G.A. at (703) 841-8490. Price per copy is $6 for employees of member companies and associates and $12 for other customers.

Investments: Analysis and Management

Fifth Edition

Jack Clark Francis

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Investments: Analysis and Management

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Beta Measurements The beta coefficient is an *index of systematic risk*. Beta coefficients may be used for ranking the systematic risk of different assets. If the beta is larger than 1, $b > 1.0$, then the asset is more volatile than the market and is called an **aggressive asset.** If the beta is less than 1, $b < 1.0$, the asset is a **defensive asset;** its price fluctuations are less volatile than the market's. Figure 10-1 illustrates the characteristic lines for three different assets that have low, medium, and high levels of beta (or undiversifiable risk).

Figure 10-2 shows that IBM is a stock with an average amount of systematic risk. IBM's beta of 1.02 indicates that its return tends to increase 2 percent more than the return on the market average when the market is rising. When the market falls, IBM's return tends to fall 2 percent more than the market's. The characteristic line for IBM has an above average correlation coefficient of $\rho = .7495$, indicating that the returns on this security follow its particular characteristic line slightly more closely than those of the average stock.

Partitioning Risk

Total risk can be measured by the variance of returns, denoted Var(r). This measure of *total risk is partitioned into its systematic and unsystematic components in Equation (10-8).*[7]

$$\begin{aligned}\mathrm{Var}(r_i) &= \text{total risk of } i\text{th asset}\\ &= \mathrm{Var}(a_i + b_i r_{m,t} + e_{i,t})\\ &\quad \text{by substituting } (a_i + b_i r_{m,t} + e_{i,t}) \text{ for } r_{i,t}\\ &= 0 + \mathrm{Var}(b_i r_{m,t}) + \mathrm{Var}(e_{i,t})\\ &\quad \text{since } \mathrm{Var}(a_i) = 0\end{aligned} \tag{10-8}$$

$$\begin{aligned}\mathrm{Var}(r_i) &= b_i^2\,\mathrm{Var}(r_m) + \mathrm{Var}(e) \qquad \text{since } \mathrm{Var}(b_i r_m) = b_i^2\,\mathrm{Var}(r_m)\\ &= \text{systematic} + \text{unsystematic risk}\end{aligned} \tag{10-8a}$$

$$.01389 = .00780 + .00609 \qquad \text{for IBM}$$

The unsystematic risk measure Var(e) is called in regression language the *residual variance* or, synonymously, the *standard error squared*.

Undiversifiable Proportion The percentage of total risk that is systematic can be measured by the coefficient of determination ρ^2 (that is, the characteristic line's squared correlation coefficient).

[7]In this context, **partition** is a technical statistical term that means to divide the total variance into *mutually exclusive* and *exhaustive* pieces. This partition is only possible if the returns from the market are statistically independent from the residual error terms that occur simultaneously, $\mathrm{Cov}(r_{m,t}, e_{i,t}) = 0$. The mathematics of regression analysis will orthogonalize the residuals and thus ensure that the needed statistical independence exists.

$$\frac{\text{Systematic risk}}{\text{Total risk}} = \frac{b_i^2\ \text{Var}(r_m)}{\text{Var}(r_m)} = \rho^2 \tag{10-9}$$

$$\frac{.007802}{.01389} = \frac{(1.021)^2\ (.00749)}{.00749} = .5617 \times 100 = 56.17\% \qquad \text{for IBM}$$

Diversifiable Proportion The percentage of unsystematic risk equals $(1.0 - \rho^2)$.

$$\frac{\text{Unsystematic risk}}{\text{Total risk}} = \frac{\text{Var}(e)}{\text{Var}(r_i)} = (1.0 - \rho^2)$$

$$\frac{.00609}{.01389} = (1.0 - .5617) = .438 \times 100 \tag{10-10}$$

$$= 43.8\%\ \text{unsystematic} \qquad \text{for IBM}$$

Studies of the characteristic lines of hundreds of stocks listed on the NYSE indicate that the average correlation coefficient is approximately $\rho = .5$.[8] This means that about $\rho^2 = 25$ percent of the total variability of return in most NYSE securities is explained by movements in the market.

	NYSE average	IBM
Systematic risk: ρ^2	.25	.5617
Unsystematic risk: $(1.0 - \rho^2)$	.75	.4383
Total risk: 100%	1.00	1.0000

As explained above, systematic changes are common to all stocks and are therefore undiversifiable.

A primary use of the characteristic line (or *market model*, or the *single-index model*, as it is also called) is to assess the risk characteristics of one asset.[9] The statistics in Table 10-2, for instance, indicate that IBM's common stock is slightly more risky than the average common stock in terms of total risk and

[8]The average ρ was found to be about .5, as reported in Marshall Blume, "On the Assessment of Risk," *Journal of Finance*, March 1971, p. 4. For similar estimates, see J. C. Francis, "Statistical Analysis of Risk Surrogates for NYSE Stocks," *Journal of Financial and Quantitative Analysis*, Dec. 1979.

[9]Professor Jensen reformulated the characteristic line in a risk-premium form. See M. C. Jensen, "The Performance of Mutual Funds in the Period 1945 through 1964," *Journal of Finance*, May 1968, pp. 389–416. See also M. C. Jensen, "Risk, the Pricing of Capital Assets, and the Evaluation of Investment Portfolios," *Journal of Business*, vol. XLII, 1969. Jensen interprets the alpha intercept term of the characteristic line, as he formulates it, as an investment performance measure. It has been suggested that Jensen's performance measure is biased. See Keith V. Smith and Dennis A. Tito, "Risk-Return Measures of Ex-Post Portfolio Performance," *Journal of Financial and Quantitative Analysis*, Dec. 1969, vol. IV, no. 4, p. 466.

systematic risk.[10] New risk measurements must be made periodically, however, because the risk and return of an asset may change with the passage of time.[11]

10-3 CAPITAL ASSET PRICING MODEL (CAPM)

An old axiom states "there is no such thing as a free lunch." This means that you cannot expect to get something for nothing—a rule that certainly applies to investment returns. Investors who want to earn high average rates of return must take high risks and endure the associated loss of sleep, the possibility of ulcers, and the chance of bankruptcy. The question to which we now turn is: Should investors worry about total risk, undiversifiable risk, diversifiable risk, or all three?

In Chapter 1 it was suggested that *investors should seek investments that have the maximum expected return in their risk class*. Their happiness from investing is presumed to be derived as indicated in the expected utility $E(U)$ function below.

$$E(U) = f[E(r), \sigma]$$

The investment preferences of wealth-seeking risk-averse investors represented by the function above cause them to maximize their expected utility (or, equivalently, happiness) by (1) maximizing their expected return in any given risk class, $\partial E(U)/\partial E(r) > 0$, or, conversely, (2) minimizing their total risk at any given rate of expected return, $\partial E(U)/\partial \sigma < 0$. However, in selecting individual assets, investors will not be particularly concerned with the asset's total risk σ. Figure 9-1 showed that the unsystematic portion of total risk can be easily diversified by holding a portfolio of different securities. But, systematic risk affects all stocks in the market because it is undiversifiable. Portfolio theory therefore suggests that only the undiversifiable (or systematic) risk is worth avoiding.[12]

[10]Statements about the relative degree of total risk are made in the context of a long-run horizon—that is, over at least one *complete business cycle*. Obviously, an accurate short-run forecast which says that some particular company will go bankrupt next quarter makes it more risky than IBM, although IBM may have had more historical variability of return.

[11]Empirical studies documenting the intertemporal instability of betas have been published. Marshall Blume, "Betas and Their Regression Tendencies," *Journal of Finance*, June 1975, pp. 785–795. See also J. C. Francis, "Statistical Analysis of Risk Coefficients for NYSE Stocks," *Journal of Financial and Quantitative Analysis*, Dec. 1979, vol. XIV, no. 5, pp. 981–997. An appendix at the end of this chapter reviews some evidence about shifting betas, standard deviations, and correlations.

[12]Both the systematic and unsystematic portions of total risk must be considered by **undiversified investors.** Entrepreneurs who have their entire net worth invested in one business, for example, can be bankrupted by a piece of bad luck that could be easily averaged away to zero in a diversified portfolio. Poorly diversified investors should not treat diversifiable risk lightly. Only well-diversified investors can afford to ignore diversifiable risk.

The Potomac Edison Company
Summary of Cost of Equity Models Applied to
Proxy Group of Fifty Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Thirteen Electric Utilities

Principal Methods	Proxy Group of Fifty Non-Price Regulated Companies	
Discounted Cash Flow Model (DCF) (1)	11.72	%
Risk Premium Model (RPM) (2)	13.40	
Capital Asset Pricing Model (CAPM) (3)	12.59	
Mean	12.57	%
Median	12.59	%
Average of Mean and Median	12.58	%

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.
(3) From page 6 of this Schedule.

The Potomac Edison Company
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Thirteen Electric Utilities

	[1]	[2]	[3]	[4]	[6]	[7]	[8]
Proxy Group of Fifty Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (1)
Agilent Technologies	0.63 %	12.00 %	10.00 %	11.97 %	11.32 %	0.67 %	11.99 %
Abbott Labs.	1.97	7.00	5.10	8.30	6.80	2.04	8.84
Analog Devices	1.94	11.50	12.30	14.87	12.89	2.07	14.96
Assurant Inc.	2.12	15.50	12.70	17.40	15.20	2.28	17.48
Smith (A.O.)	2.14	11.50	9.00	8.00	9.50	2.24	11.74
Air Products & Chem.	2.28	11.00	12.20	10.65	11.28	2.41	13.69
Ball Corp.	1.54	21.50	5.00	4.51	10.34	1.62	11.96
Brown-Forman 'B'	1.21	14.50	NA	8.62	11.56	1.28	12.84
Bristol-Myers Squibb	3.02	NA	5.60	4.14	4.87	3.09	7.96
Broadridge Fin'l	2.05	9.50	NA	11.80	10.65	2.16	12.81
Brady Corp.	2.00	12.50	7.00	7.00	8.83	2.09	10.92
CACI Int'l	-	7.00	6.70	2.40	5.37	-	NA
Chemed Corp.	0.31	7.00	6.90	6.95	6.95	0.32	7.27
Cooper Cos.	0.02	12.00	11.00	10.00	11.00	0.02	11.02
CSW Industrials	0.57	11.50	NA	12.00	11.75	0.60	12.35
Quest Diagnostics	1.83	4.00	NA	(15.60)	4.00	1.87	5.87
Dolby Labs.	1.57	9.50	16.00	16.00	13.83	1.68	15.51
Lauder (Estee)	1.18	14.00	9.60	5.03	9.54	1.24	10.78
Exponent, Inc.	0.98	10.50	NA	15.00	12.75	1.04	13.79
FactSet Research	0.84	10.50	10.00	11.90	10.80	0.89	11.69
Gentex Corp.	1.79	10.00	16.60	15.80	14.13	1.92	16.05
Ingredion Inc.	3.06	8.00	NA	9.90	8.95	3.20	12.15
Hunt (J.B.)	0.91	11.00	15.00	14.98	13.66	0.97	14.63
J&J Snack Foods	1.88	9.00	NA	73.10	9.00	1.96	10.96
Henry (Jack) & Assoc	1.06	8.00	9.00	9.00	8.67	1.11	9.78
L3Harris Technologie	1.98	17.50	2.70	41.80	10.10	2.08	12.18
McCormick & Co.	1.93	5.00	5.30	5.10	5.13	1.98	7.11
Altria Group	8.27	5.50	4.00	4.16	4.55	8.46	13.01
MSA Safety	1.40	7.00	NA	18.00	12.50	1.49	13.99
MSCI Inc.	1.07	14.50	NA	12.53	13.52	1.14	14.66
Motorola Solutions	1.40	10.50	9.00	11.18	10.23	1.47	11.70
Mettler-Toledo Int'l	-	13.50	12.20	12.20	12.63	-	NA
Northrop Grumman	1.32	6.50	3.30	3.00	4.27	1.35	5.62
Old Dominion Freight	0.42	10.50	14.10	14.54	13.05	0.45	13.50
Packaging Corp.	3.98	11.00	5.00	(5.16)	8.00	4.14	12.14
Post Holdings	-	5.00	NA	32.40	5.00	-	NA
RLI Corp.	0.83	12.00	NA	9.80	10.90	0.88	11.78
Rollins, Inc.	1.33	10.50	NA	8.20	9.35	1.39	10.74
Service Corp. Int'l	1.61	2.00	12.00	12.00	8.67	1.68	10.35
Sherwin-Williams	1.03	11.50	12.80	11.46	11.92	1.09	13.01
Selective Ins. Group	1.31	9.50	6.60	13.40	9.83	1.37	11.20
Sirius XM Holdings	1.57	32.50	7.00	3.54	5.27	1.61	6.88
Sensient Techn.	2.29	2.50	NA	3.80	3.15	2.33	5.48
Thermo Fisher Sci.	0.23	10.50	12.50	3.51	8.84	0.24	9.08
Texas Instruments	2.97	7.50	9.30	10.00	8.93	3.10	12.03
U-Haul Holding	-	11.50	NA	15.00	13.25	-	NA
UniFirst Corp.	0.68	10.50	NA	10.00	10.25	0.71	10.96
VeriSign Inc.	-	11.00	NA	8.00	9.50	-	NA
Waters Corp.	-	6.00	7.20	8.34	7.18	-	NA
Watsco, Inc.	3.35	11.50	NA	15.00	13.25	3.57	16.82
						Mean	11.57 %
						Median	11.87 %
						Average of Mean and Median	11.72 %

NA= Not Available

(1) The application of the DCF model to the domestic, non-price regluated comparable risk companies is identical to the application of the DCF to the utility proxy group. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of December 30, 2022. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, Bloomberg, www.zacks.com, and www.yahoo.com (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

Source of Information: Value Line Investment Survey
www.zacks.com Downloaded on 12/30/2022
www.yahoo.com Downloaded on 12/30/2022
Bloomberg Professional Services

The Potomac Edison Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Fifty Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	6.05 %
2.	Adjustment to Reflect Proxy Group Bond Rating (2)	(0.17)
3.	Adjusted Bond Yield Applicable to the Non-Price Regulated Proxy Group	5.88 %
4.	Equity Risk Premium (3)	7.52
5.	Risk Premium Derived Common Equity Cost Rate	13.40 %

Notes: (1) Average forecast of Baa2 corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated January 1, 2023 and December 2, 2022 (see pages 10 and 11 of Schedule DWD-3). The estimates are detailed below.

First Quarter 2023	6.10 %
Second Quarter 2023	6.30
Third Quarter 2023	6.20
Fourth Quarter 2023	6.10
First Quarter 2024	5.90
Second Quarter 2024	5.80
2024-2028	6.00
2029-2033	6.00
Average	6.05 %

(2) To reflect the Baa1 average rating of the Non-Price Regulated Proxy Group, the prosepctive yield on Baa2 corporate bonds must be adjusted downward by 1/3 of the spread between A2 and Baa2 corporate bond yields as shown below:

	A2 Corp. Bond Yield	Baa2 Corp. Bond Yield	Spread
Dec-2022	5.10 %	5.58 %	0.48 %
Nov-2022	5.58	6.07	0.49
Oct-2022	5.74	6.26	0.52
		Average yield spread	0.50 %
		1/3 of spread	0.17 %

(3) From page 5 of this Schedule.

The Potomac Edison Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Fifty Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Thirteen Electric Utilities

	Moody's Long-Term Issuer Rating December 2022		Standard & Poor's Long-Term Issuer Rating December 2022	
Proxy Group of Fifty Non-Price Regulated Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Agilent Technologies	Baa2	9.0	BBB+	8.0
Abbott Labs.	A1	5.0	AA-	4.0
Analog Devices	A3	7.0	A-	7.0
Assurant Inc.	Baa2	9.0	BBB	9.0
Smith (A.O.)	NA	--	NA	--
Air Products & Chem.	A2	6.0	A	6.0
Ball Corp.	Ba1	11.0	BB+	11.0
Brown-Forman 'B'	A1	5.0	A-	7.0
Bristol-Myers Squibb	A2	6.0	A+	5.0
Broadridge Fin'l	Baa1	8.0	BBB+	8.0
Brady Corp.	NA	--	NA	--
CACI Int'l	NA	--	BB+	11.0
Chemed Corp.	WR	--	NR	--
Cooper Cos.	WR	--	NR	--
CSW Industrials	NA	--	NA	--
Quest Diagnostics	Baa2	9.0	BBB+	8.0
Dolby Labs.	NA	--	NA	--
Lauder (Estee)	A1	5.0	A+	5.0
Exponent, Inc.	NA	--	NA	--
FactSet Research	Baa3	10.0	NA	--
Gentex Corp.	NA	--	NA	--
Ingredion Inc.	Baa1	8.0	BBB	9.0
Hunt (J.B.)	Baa1	8.0	BBB+	8.0
J&J Snack Foods	NA	--	NA	--
Henry (Jack) & Assoc	NA	--	NA	--
L3Harris Technologie	Baa2	9.0	BBB	9.0
McCormick & Co.	Baa2	9.0	BBB	9.0
Altria Group	A3	7.0	BBB	9.0
MSA Safety	NA	--	NA	--
MSCI Inc.	Ba1	11.0	BB+	11.0
Motorola Solutions	Baa3	10.0	BBB-	10.0
Mettler-Toledo Int'l	WR	--	NR	--
Northrop Grumman	Baa1	8.0	BBB+	8.0
Old Dominion Freight	NA	--	NA	--
Packaging Corp.	Baa2	9.0	BBB	9.0
Post Holdings	B2	15.0	B+	14.0
RLI Corp.	Baa2	9.0	BBB	9.0
Rollins, Inc.	NA	--	NA	--
Service Corp. Int'l	Ba3	13.0	BB+	11.0
Sherwin-Williams	Baa2	9.0	BBB	9.0
Selective Ins. Group	Baa2	9.0	BBB	9.0
Sirius XM Holdings	NA	--	NA	--
Sensient Techn.	WR	--	NR	--
Thermo Fisher Sci.	A3	7.0	A-	7.0
Texas Instruments	Aa3	4.0	A+	5.0
U-Haul Holding	WR	--	NR	--
UniFirst Corp.	NA	--	NA	--
VeriSign Inc.	Baa3	10.0	BBB	9.0
Waters Corp.	NA	--	NA	--
Watsco, Inc.	NA	--	NA	--
Average	Baa1	8.4	BBB+	8.4

Notes:
(1) From page 6 of Schedule DWD-3.

Source of Information:
Bloomberg Professional Services

The Potomac Edison Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Proxy Group of Fifty Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Thirteen Electric Utilities

Line No.	Equity Risk Premium Measure	Proxy Group of Fifty Non-Price Regulated Companies
1.	Kroll Equity Risk Premium (1)	6.13 %
2.	Regression on Kroll Risk Premium Data (2)	7.26
3.	Kroll Equity Risk Premium based on PRPM (3)	9.76
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	11.53
5	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	10.62
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	6.01
7.	Conclusion of Equity Risk Premium	8.55 %
8.	Adjusted Beta (7)	0.88
9.	Forecasted Equity Risk Premium	7.52 %

Notes:
(1) From note 1 of page 9 of Schedule DWD-3.
(2) From note 2 of page 9 of Schedule DWD-3.
(3) From note 3 of page 9 of Schedule DWD-3.
(4) From note 4 of page 9 of Schedule DWD-3.
(5) From note 5 of page 9 of Schedule DWD-3.
(6) From note 6 of page 9 of Schedule DWD-3.
(7) Average of mean and median beta from page 6 of this Schedule.

Sources of Information:
Stocks, Bonds, Bills, and Inflation - 2022 SBBI Yearbook, Kroll, Inc.
Value Line Summary and Index
Blue Chip Financial Forecasts, January 1, 2023 and December 2, 2022
Bloomberg Professional Services

The Potomac Edison Company
Traditional CAPM and ECAPM Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Thirteen Electric Utilities

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Fifty Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Agilent Technologies	0.85	0.77	0.81	9.75 %	3.91 %	11.81 %	12.27 %	12.04 %
Abbott Labs.	0.90	0.81	0.86	9.75	3.91	12.29	12.64	12.47
Analog Devices	1.00	0.87	0.94	9.75	3.91	13.07	13.22	13.15
Assurant Inc.	0.90	0.85	0.88	9.75	3.91	12.49	12.78	12.64
Smith (A.O.)	0.90	0.76	0.83	9.75	3.91	12.00	12.42	12.21
Air Products & Chem.	0.90	0.79	0.85	9.75	3.91	12.20	12.56	12.38
Ball Corp.	1.05	0.91	0.98	9.75	3.91	13.46	13.51	13.49
Brown-Forman 'B'	0.85	0.80	0.83	9.75	3.91	12.00	12.42	12.21
Bristol-Myers Squibb	0.80	0.76	0.78	9.75	3.91	11.51	12.05	11.78
Broadridge Fin'l	0.90	0.70	0.80	9.75	3.91	11.71	12.20	11.95
Brady Corp.	0.95	0.93	0.94	9.75	3.91	13.07	13.22	13.15
CACI Int'l	0.90	0.84	0.87	9.75	3.91	12.39	12.71	12.55
Chemed Corp.	0.80	0.70	0.75	9.75	3.91	11.22	11.83	11.53
Cooper Cos.	0.95	0.90	0.93	9.75	3.91	12.98	13.15	13.06
CSW Industrials	0.85	0.80	0.83	9.75	3.91	12.00	12.42	12.21
Quest Diagnostics	0.80	0.69	0.75	9.75	3.91	11.22	11.83	11.53
Dolby Labs.	0.95	0.88	0.92	9.75	3.91	12.88	13.07	12.98
Lauder (Estee)	1.05	0.92	0.99	9.75	3.91	13.56	13.59	13.57
Exponent, Inc.	0.90	0.80	0.85	9.75	3.91	12.20	12.56	12.38
FactSet Research	1.00	0.93	0.97	9.75	3.91	13.37	13.44	13.40
Gentex Corp.	0.95	0.90	0.93	9.75	3.91	12.98	13.15	13.06
Ingredion Inc.	0.90	0.85	0.88	9.75	3.91	12.49	12.78	12.64
Hunt (J.B.)	0.95	0.90	0.93	9.75	3.91	12.98	13.15	13.06
J&J Snack Foods	0.90	0.87	0.89	9.75	3.91	12.59	12.86	12.72
Henry (Jack) & Assoc	0.85	0.70	0.78	9.75	3.91	11.51	12.05	11.78
L3Harris Technologie	0.90	0.92	0.91	9.75	3.91	12.78	13.00	12.89
McCormick & Co.	0.75	0.66	0.71	9.75	3.91	10.83	11.54	11.19
Altria Group	0.90	0.88	0.89	9.75	3.91	12.59	12.86	12.72
MSA Safety	1.00	0.92	0.96	9.75	3.91	13.27	13.37	13.32
MSCI Inc.	1.05	0.85	0.95	9.75	3.91	13.17	13.29	13.23
Motorola Solutions	0.90	0.79	0.85	9.75	3.91	12.20	12.56	12.38
Mettler-Toledo Int'l	0.95	0.89	0.92	9.75	3.91	12.88	13.07	12.98
Northrop Grumman	0.80	0.74	0.77	9.75	3.91	11.42	11.98	11.70
Old Dominion Freight	0.95	0.85	0.90	9.75	3.91	12.68	12.93	12.81
Packaging Corp.	0.95	0.90	0.93	9.75	3.91	12.98	13.15	13.06
Post Holdings	NMF	0.86	0.86	9.75	3.91	12.29	12.64	12.47
RLI Corp.	0.80	0.66	0.73	9.75	3.91	11.03	11.69	11.36
Rollins, Inc.	0.85	0.72	0.79	9.75	3.91	11.61	12.12	11.87
Service Corp. Int'l	0.95	0.89	0.92	9.75	3.91	12.88	13.07	12.98
Sherwin-Williams	0.95	0.84	0.90	9.75	3.91	12.68	12.93	12.81
Selective Ins. Group	0.85	0.81	0.83	9.75	3.91	12.00	12.42	12.21
Sirius XM Holdings	0.90	0.86	0.88	9.75	3.91	12.49	12.78	12.64
Sensient Techn.	0.95	0.82	0.89	9.75	3.91	12.59	12.86	12.72
Thermo Fisher Sci.	0.85	0.70	0.78	9.75	3.91	11.51	12.05	11.78
Texas Instruments	0.90	0.75	0.83	9.75	3.91	12.00	12.42	12.21
U-Haul Holding	0.95	0.92	0.94	9.75	3.91	13.07	13.22	13.15
UniFirst Corp.	0.95	0.91	0.93	9.75	3.91	12.98	13.15	13.06
VeriSign Inc.	0.95	0.78	0.87	9.75	3.91	12.39	12.71	12.55
Waters Corp.	0.95	0.87	0.91	9.75	3.91	12.78	13.00	12.89
Watsco, Inc.	0.85	0.75	0.80	9.75	3.91	11.71	12.20	11.95
Mean			0.87			12.38 %	12.70 %	12.54 %
Median			0.88			12.49 %	12.78 %	12.64 %
Average of Mean and Median			0.88			12.44 %	12.74 %	12.59 %

NMF = Not Meaningful Figure

Notes:
(1) From Schedule DWD-4, note 1.
(2) From Schedule DWD-4, note 2.
(3) Average of CAPM and ECAPM cost rates.

The Potomac Edison Company
Derivation of Investment Risk Adjustment Based upon
Kroll Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on December 30, 2022 (1) (millions)	(times larger)	[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	The Potomac Edison Company	$ 681.540		8	1.21%	
2.	Proxy Group of Thirteen Electric Utilities	$ 22,798.483	33.5 x	2	0.43%	0.78%

	[A] Decile	[B] Market Capitalization of Smallest Company (millions)	[C] Market Capitalization of Largest Company (millions)	[D] Size Premium (Return in Excess of CAPM)*
Largest	1	$ 36,160.584	$ 2,324,390.219	-0.22%
	2	16,759.390	36,099.221	0.43%
	3	8,216.356	16,738.364	0.55%
	4	5,019.883	8,212.638	0.54%
	5	3,281.009	5,003.747	0.89%
	6	2,170.315	3,276.553	1.18%
	7	1,306.402	2,164.524	1.34%
	8	629.118	1,306.038	1.21%
	9	290.002	627.803	2.10%
Smallest	10	10.588	289.007	4.80%

*From 2022 Kroll Cost of Capital Navigator

Notes:
(1) From page 2 of this Schedule.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.78% in Column [4], Line No. 2 is derived as follows 0.78% = 1.21% - 0.43%.

The Potomac Edison Company
Market Capitalization of The Potomac Edison Company and
the Proxy Group of Thirteen Electric Utilities

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Exchange	Common Stock Shares Outstanding at Fiscal Year End 2021	Book Value per Share at Fiscal Year End 2020 (1)	Total Common Equity at Fiscal Year End 2021	Closing Stock Market Price on December 30, 2022	Market-to-Book Ratio on December 30, 2022 (2)	Market Capitalization on December 30, 2022 (3)
		(millions)		(millions)			(millions)
The Potomac Edison Company		NA	NA	$ 347.902 (4)	NA		
Based upon Proxy Group of Thirteen Electric Utilities						195.9 (5)	$ 681.540 (6)
Proxy Group of Thirteen Electric Utilities							
Alliant Energy Corporation	NASDAQ	250.475	$ 23.915	$ 5,990.000	$ 55.210	230.9 %	$ 13,828.699
Ameren Corporation	NYSE	257.700	37.641	9,700.000	88.920	236.2	22,914.684
American Electric Power Corporation	NASDAQ	504.212	44.492	22,433.200	94.950	213.4	47,874.931
Duke Energy Corporation	NYSE	769.000	61.553	47,334.000	102.990	167.3	79,199.310
Edison International	NASDAQ	380.378	36.572	13,911.000	63.620	174.0	24,199.658
Entergy Corporation	NYSE	202.653	57.425	11,637.284	112.500	195.9	22,798.483
Evergy, Inc.	NYSE	229.300	40.316	9,244.400	62.930	156.1	14,429.843
Eversource Energy	NYSE	344.403	42.392	14,599.844	83.840	197.8	28,874.764
IDACORP, Inc.	NYSE	50.516	52.823	2,668.436	107.850	204.2	5,448.202
NorthWestern Corporation	NYSE	57.606	40.616	2,339.713	59.340	146.1	3,418.355
OGE Energy Corporation	NASDAQ	200.500	20.231	4,056.300	39.550	195.5	7,929.775
Portland General Electric Company	NYSE	89.411	30.276	2,707.000	49.000	161.8	4,381.120
Xcel Energy Inc.	NYSE	544.025	28.697	15,612.000	70.110	244.3	38,141.612
Median		250.475	$ 40.316	$ 9,700.000	$ 70.110	195.9 %	$ 22,798.483

NA= Not Available

Notes: (1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of The Potomac Edison Company on December 30, 2022 is assumed to be equal to the market-to-book ratio of Proxy Group of Thirteen Electric Utilities on December 30, 2022 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2021 Annual Forms 10K
Bloomberg Financial Services

The Potomac Edison Company
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances since 2003

Date of Offering	Transaction (1)	[Column 1] Shares Issued (1)	[Column 2] Market Price per Share (1)	[Column 3] Average Offering Price per Share (1)	[Column 4] Market Pressure (2)	[Column 5] Issuance Expense	[Column 6] Net Proceeds per Share (3)	[Column 7] Gross Equity Issue before Costs (4)	[Column 8] Total Net Proceeds (5)	[Column 9] Total Flotation Costs (6)	[Column 10] Flotation Cost Percentage (7)
9/11/2003	Equity Offering	32,200,000	$ 31.1000	$ 30.0000	$ 1.10	$ 0.975	$ 29.0250	$ 1,001,420,000	$ 934,605,000	$ 66,815,000	6.67%
12/13/2021	Equity Offering	25,588,535	$ 40.1700	$ 39.0800	$ 1.09	$ 1.016	$ 38.0639	$ 999,999,948	$ 973,999,948	$ 53,891,503	2.60%
								$ 2,001,419,948	$ 1,908,604,948	$ 120,706,503	4.64%

Flotation Cost Adjustment

	[Column 11] Average Dividend Yield (8)	[Column 12] Average Projected EPS Growth Rate (8)	[Column 13] Adjusted Dividend Yield (8)	[Column 14] Average DCF Cost Rate Unadjusted for Flotation (9)	[Column 15] DCF Cost Rate Adjusted for Flotation (10)	[Column 16] Flotation Cost Adjustment (11)
Proxy Group of Thirteen Electric Utilities	3.75 %	5.39 %	3.85 %	9.24 %	9.43 %	0.19 %

Notes:
(1) From Company SEC filings
(2) Col. 2 - Col. 3
(3) Col. 2 - Col. 4 - Col. 5
(4) Col. 1 x Col. 2
(5) Col. 1 x Col. 6
(6) Col. 1 *(Col. 4 + Col. 5)
(7) (Col. 7 - Col. 8) / Col. 7
(8) From Schedule DWD-2
(9) Col. 12 + Col. 13
(10) (Col. 13 / (1 - Col. 10)) + Col. 12
(11) Col. 15 - Col. 14

Source of Information: Company SEC filings.

The Potomac Edison Company
Derivation of Credit Adjusted Risk Free Rate

Observed Spreads

	30 Year T-Bond	Baa Utility Bond	Spread
Dec-2022	3.66 %	5.56 %	1.90 %
Nov-2022	4.00	6.05	2.05
Oct-2022	4.04	6.18	2.14
Average	3.90 %	5.93 %	2.03 %

3 month average 30 Year T-Bond	3.90 %
3 month average 30 Year/Baa Bond Spread	2.03
Credit Adjusted Risk-Free Rate	5.93 %

Sources of Information:
Bloomberg Professional Services

BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

In the Matter of the Verified Petition of	*	
the Potomac Edison Company for	*	
Review and Approval of Increases in and	*	
Other Adjustments to Its Rates and	*	Case No. ____
Charges for Electric Service, and for	*	
Approval of Other Proposed Tariff	*	
Revisions in Connection Therewith	*	

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

Concerning: Cash Working Capital

March 22, 2023

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy S. Lyons. My business address is 3 Speen Street, Suite 150, Framingham, Massachusetts 01701.

Q. PLEASE DESCRIBE YOUR CURRENT POSITION.

A. I am a Partner at ScottMadden, Inc. ("ScottMadden").

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held several management consulting positions in the energy industry, first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden in 2016.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a bachelor's degree from St. Anselm College, a master's degree in Economics from The Pennsylvania State University, and a master's degree in Business Administration from Babson College.

Q. HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. A summary of my testimony experience is included in Exhibit TSL-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to sponsor the results of the lead-lag study conducted on behalf of The Potomac Edison Company ("PE" or the "Company"), a subsidiary of FirstEnergy Corp. ("FirstEnergy"). The lead-lag study is submitted as part of the Company's March 2023 distribution base rate filing with the Commission. The lead-lag study was used to determine the Company's Cash Working Capital ("CWC") requirement, which is included in the Company's rate base.

Q. ARE YOU SPONSORING EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibits that were prepared by me or under my direction:

- Exhibit TSL-1 – Qualifications
- Exhibit TSL-2 – Summary of the Cash Working Capital Requirement
- Exhibit TSL-3 – Workpapers supporting the Lead-Lag Study

II. OVERVIEW OF TESTIMONY

Q. PLEASE DEFINE THE TERM "WORKING CAPITAL" AS A RATE BASE COMPONENT.

A. The term "working capital" refers to the net funds required by the Company to finance goods and services used to provide service to customers from the time those goods and services are paid for by the Company to the time that payment is received from customers. Goods and services considered in the lead-lag study include: operations and maintenance ("O&M") expenses, including labor and non-labor expenses; federal, state, and local taxes; and employment taxes.

Q. HOW WAS THE COMPANY'S CASH WORKING CAPITAL REQUIREMENT DETERMINED?

A. The Company's cash working capital requirement was determined by applying the results of the lead-lag study to the Company's adjusted test year expenses. The lead-lag study compares differences between the Company's revenue lag and expense leads.

The revenue lag represents the number of days from the time customers receive their electric service to the time customers pay for their electric service, *i.e.*, when the funds are available to the Company. The longer the revenue lag, the more cash the Company needs to finance its day-to-day operations.

The expense lead represents the number of days from the time the Company receives goods and services used to provide electric service to the time payments are made for those goods and services, *i.e.*, when the funds are no longer available to the Company.

The longer the expense lead, the less cash the Company needs to fund its day-to-day operations.

Together, the revenue lag and expense leads are used to measure the lead-lag days. The lead-lag days are then applied to the Company's adjusted test year expenses to derive the CWC requirement, which is included in the Company's rate base.

III. LEAD-LAG STUDY APPROACH

Q. PLEASE DESCRIBE THE DATA USED IN THE LEAD-LAG STUDY.

A. The lead-lag study was based on data from the period January 1, 2021 through December 31, 2021 (the "study period"). The data included: customer meter reading and billing schedules; O&M expenses; and federal, state, local, and employment taxes. The data generally included service periods, payment dates, and payment amounts.

1. REVENUE LAG

Q. HOW WAS THE REVENUE LAG DETERMINED?

A. The revenue lag was based on the number of days from the time electric service was provided to customers to the time payment was received from customers. There are two categories of revenues that comprise the revenue lag: (1) retail electric revenues, and (2) other revenues.

Retail electric revenues represent the largest revenue category, consisting of revenues related to retail electric service for residential, commercial, public streetlights, and industrial customers. The revenue lag for retail electric service was measured as the sum of three components: (1) the service lag; (2) the billing lag; and (3) the collection lag.

Q. WHAT IS THE SERVICE LAG?

A. The service lag measures the average number of days in the service period, *i.e.*, the time between the start and end of the billing month. The service lag in this lead-lag study was based on the midpoint of the service period, which reflects that electricity is delivered evenly over the service period.

Q. WHAT IS THE BILLING LAG?

A. The billing lag measures the number of days from the time meters are read to the time bills are calculated and recorded. The billing lag in this lead-lag study was based on the Company's meter reading schedule.

Q. WHAT IS THE COLLECTION LAG?

A. The collection lag measures the number of days from the time bills are calculated and recorded to the time customer payments are received (i.e., funds are available to the Company). The collection lag in this lead-lag study was based on monthly accounts receivable balances and billed revenue data. Specifically, the collection lag was determined by dividing the average accounts receivable balance during the study period by the average billed revenues per day during the same period.

Q. HOW WAS THE REVENUE LAG FOR OTHER OPERATING REVENUES DETERMINED?

A. The revenue lag for other operating revenues was determined by first identifying the revenue lag for each of the four categories of other revenues; second converting the revenue lags to "dollar-days" that reflect a weighting of the categories by revenues; and finally summing the dollar days across all other operating revenues. The four categories of other revenues were: (1) late payment charges revenues, (2) miscellaneous service revenues, (3) telephone/cable pole rentals, and (4) other electric revenues.

Q. WHAT IS THE TOTAL REVENUE LAG USED IN THE LEAD-LAG STUDY?

A. The total revenue lag used in the lead-lag study is based on a weighted average of the revenue lags for retail electricity revenues and other operating revenues. The derivation of the revenue lag is shown in Exhibit TSL-3 at page 1.

2. EXPENSE LEADS

a. OPERATION AND MAINTENANCE EXPENSES

Q. PLEASE DESCRIBE DEVELOPMENT OF LEAD DAYS FOR O&M EXPENSES.

A. Lead days for O&M expenses were measured separately for the following expense categories: (1) energy purchases; (2) regular payroll; (3) incentive compensation; (4) employee benefits; (5) pension and other post-employment benefits ("OPEB"); (6) Commission annual assessment; (7) service company; (8) uncollectible; and (9) other O&M expenses.

Q. HOW WERE LEAD DAYS DETERMINED FOR ENERGY PURCHASES?

A. Lead days for energy purchases were based on a review of the Company's invoices. Lead days were measured as the number of days from the midpoint of the service period to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR PAYROLL EXPENSES?

A. Lead days for payroll expenses were based on the Company's payroll process, which pays employees on a weekly and bi-weekly basis. Lead days were measured for each payroll period as the number of days from the midpoint of the weekly and bi-weekly payroll period, individually, to the weekly and bi-weekly payment date, converted to "dollar-days" to reflect a weighting of the expense amounts, and then summed across all regular payroll expenses.

Q. DID THE STUDY SEPARATELY DETERMINE LEAD DAYS FOR INCENTIVE COMPENSATION EXPENSES?

A. Yes. Lead days for the Company's incentive compensation expenses were measured separately as the number of days from the midpoint of the performance period (i.e., when the incentive compensation was earned) to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR EMPLOYEE BENEFIT EXPENSES?

A. Lead days for employee benefit expenses were based on a review of the Company's payments for individual benefit items, including medical, dental, and 401(k) plans. Lead days were measured for each benefit item as the number of days from the midpoint of the benefit period to the payment date, converted to "dollar-days" to reflect a weighting of the expense amounts, and then summed across all benefit expenses.

Q. HOW WERE LEAD DAYS DETERMINED FOR PENSION PLAN AND OPEB PAYMENTS?

A. Lead days for pension plan and OPEB payments were zero to reflect that services are provided to the pension plan at the time payment is made.

Q. HOW WERE LEAD DAYS DETERMINED FOR THE COMMISSION ANNUAL ASSESSMENT FEES?

A. Lead days for the Commission annual assessment fees were measured as the number of days from the midpoint of the assessment period to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR FIRSTENERGY SERVICE COMPANY (AFFILIATE) EXPENSES?

A. Lead days for the FirstEnergy Service Company (Affiliate) ("FESC") expenses were based on the number of days from the midpoint of the service period to the financial settlement (payment) date via the money pool. The FESC service period is based on the calendar month. Intercompany charges are recorded during the month and are billed by FESC and settled by the various FirstEnergy companies on the first business day following the conclusion of the service period. Lead days for FESC expenses were measured as the number of days from midpoint of the service period to the financial settlement via the money pool, which is on the first business day following the conclusion of the service period.

Q. HOW WERE LEAD DAYS DETERMINED FOR UNCOLLECTIBLE EXPENSES?

A. Lead days for uncollectible expenses were based on the Company's approach to create a reserve account for uncollectible expenses prior to the actual write-off and are zero since it is a non-cash item, consistent with the Company's most recently approved lead-lag study.

Q. HOW WERE LEAD DAYS DETERMINED FOR OTHER O&M EXPENSES?

A. Lead days for other O&M expenses were based on the sum of two components: (1) lead days from the midpoint of the service period to the invoice date; and (2) lead days from the invoice date to the payment date.

Lead days from the midpoint of the service period to the invoice date were based on a stratified sample of invoices paid by the Company over the period January 1, 2021, through December 31, 2021. Lead days were measured for each invoice in the sample as the number of days from the midpoint of the service period to the invoice date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount and then summed by invoice amounts to determine the lead days. The study relied on a sample of invoices to measure the lead days because the service periods were not readily available electronically and required detailed inspection of individual invoices.

Lead days from the invoice date to the payment date were based on the full population of invoices paid by the Company over the period January 1, 2021, through December 31, 2021. Lead days were measured for each invoice as the number of days from the invoice date to the payment date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount and then summed by invoice amounts to determine the lead days.

b. CURRENT INCOME TAX EXPENSE

Q. HOW WERE LEAD DAYS DETERMINED FOR FEDERAL INCOME TAXES?

A. Lead days for federal income taxes were based on due dates for tax payments: April 15, June 15, September 15, and December 15. Lead days for federal income taxes were measured as the number of days from the midpoint of the taxing period (*i.e.*, the calendar year) to the due dates. The study assumes the tax payments reflect equal installments.

Q. HOW WERE LEAD DAYS DETERMINED FOR STATE INCOME TAXES?

A. Lead days for state income taxes were based on due dates for tax payments: April 15, May 15, and June 15. Lead days for state income taxes were measured as the number of days from the midpoint of the taxing period (*i.e.*, the calendar year) to the due dates. The study assumes the tax payments reflect equal installments.

c. TAXES OTHER THAN INCOME TAXES

Q. HOW WERE LEAD DAYS DETERMINED FOR TAXES OTHER THAN INCOME TAXES?

A. Lead days for Taxes Other Than Income Taxes were measured separately for the following categories: (1) payroll-related taxes (Federal Insurance Contributions Act ("FICA"), federal unemployment, and state unemployment); (2) property taxes; (3) gross receipt taxes; (5) kilowatt-hour ("kWh") taxes; and (7) sales and use taxes.

Q. HOW WERE LEAD DAYS DETERMINED FOR EACH OF THESE TAXES?

A. Lead days for FICA taxes were measured as the number of days from the payroll payment date of the applicable pay period to the FICA payment date plus the payroll lead days.

Lead days for federal and state unemployment taxes were measured as 30 days after the end of each quarter. These taxes were then converted to "dollar days" to reflect a weighting by expense amount and then summed by payment amounts to determine the lead days.

Lead days for property taxes were measured as the number of days from the midpoint of the taxing period to the payment date. These taxes were then converted to "dollar days" to reflect a weighting by expense amount and then summed by payment amounts to determine the lead days.

Lead days for gross receipts, kWh, and sales and use taxes were measured as the number of days from the midpoint of the taxing period to the payment date. These taxes were then converted to "dollar days" to reflect a weighting by expense amount and then summed by payment amounts to determine the lead days.

d. INTEREST EXPENSES

Q. DID YOU CALCULATE LEAD DAYS FOR INTEREST PAYMENTS?

A. Yes. Lead days for interest payments related to long-term debt were measured as the number of days from the midpoint of the service period to the payment date for the study period. These interest payments were then converted to "dollar days" to reflect a weighting by expense amount and then summed by payment amounts to determine the lead days.

Lead days for interest on customer deposits were measured as the midpoint of the service period of one year for Residential customers and of the service period of two years for Non-Residential customers.

IV. CONCLUSION

Q. WHAT WERE THE RESULTS OF THE LEAD-LAG STUDY?

A. The results of the lead-lag study are included in Exhibit TSL-2.

Q. ARE THE RESULTS OF THIS LEAD-LAG STUDY REASONABLE?

A. Yes, the study provides an accurate assessment of the Company's actual cash working capital requirements. The resulting cash working capital requirement should be included in the Company's rate base.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Summary of Qualifications

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rates and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim served as Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony and evidence before 23 state regulatory commissions and 2 Canadian regulatory boards. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. from Babson College.

Areas of Specialization

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas

Capabilities

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
Cook Inlet Natural Gas Storage Alaska, LLC	7/21	Docket No. U-21-058	Sponsored testimony supporting the lead-lag study/cash working capital requirement for a general rate case proceeding.
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted and sponsored testimony supporting a lead-lag study for a general rate case proceeding.
Arizona Corporation Commission			
Southwest Gas Corporation	12/21	Docket No. G-01551A-21-0368	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (The Empire District Electric Company)	2/23	Docket No. 22-085-U	Sponsored testimony supporting the class cost of service, rate design, bill impact studies, and revenue decoupling for a general rate case proceeding.
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
California Public Utilities Commission			
Bear Valley Electric Service, Inc.	10/22	Application No. 22-08-010	Sponsored testimony supporting marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Liberty Utilities (CalPeco Electric)	5/21	Application No. 21-05-017	Sponsored testimony supporting the lead-lag study/cash working capital, marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Southwest Gas Corporation (Southern California, Northern California, and South Lake Tahoe jurisdictions)	8/19	Application No. 19-08-015	Sponsored testimony on behalf of three separate rate jurisdictions supporting revenue requirements, lead-lag/ cash working capital, and class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Illinois Commerce Commission			
Ameren Illinois Company d/b/a Ameren Illinois	1/23	Docket No. 22-0487	Sponsored testimony supporting a Multi-Year Integrated Grid Plan (Grid Plan). Prepared research and analysis evaluating the reasonableness of the Grid Plan through comparison to how other electric utilities have responded to the changing energy landscape.
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			

Sponsor	Date	Docket No.	Subject
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Kentucky Public Service Commission			
Bluegrass Water Utility (Central States Water Company)	02/23	Case No. 2022-00432	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
Maine Public Utilities Commission			
Maine Water Company	03/21	Docket No. 2021-00053	Sponsored testimony supporting a proposed rate smoothing mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
Berkshire Gas Company, Eversource Energy, Liberty Utilities, National Grid, and Unitil	03/22	Docket No. DPU 20-80	Sponsored report that summarizes research, findings, and recommendations for regulatory mechanisms, methodologies, and policies that support Massachusetts's achievement of its net zero climate goal by 2050. The regulatory designs were informed by the results of quantitative and qualitative analysis of decarbonization pathways to achieve the Commonwealth's climate goals.
Liberty Utilities (New England Gas Company)	08/20	Docket No. DPU 20-92	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2020/2021 through 2024/2025.
Eversource Energy, National Grid, and Unitil	02/20	Docket No. DPU 19-55	Sponsored report that summarizes research and evaluation of funding approaches for infrastructure modifications that interconnect Distributed Generation (DG) projects.
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.

Sponsor	Date	Docket No.	Subject
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Minnesota Public Utilities Commission			
Northern States Power Company (XcelEnergy)	10/21	Docket No. E002/GR-21-630	Sponsored testimony supporting a Return on Equity (ROE)adjustment mechanism that would allow the Company to symmetrically adjust its ROE to reflect significant changesin financial market conditions.
Missouri Public Service Commission			
Confluence Rivers Utility Operating Company	12/22	Case No. WR-2023-0006/ SR-2023-0007	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
The Empire District Gas Company	08/21	Docket No. GR-2021-0320	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
The Empire District Electric Company	05/21	Docket No. ER-2021-0312	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Spire Missouri, Inc.	12/20	Docket No. GR-2021-0108	Sponsored testimony supporting class cost of service, rate design, and lead-lag study proposals for a general rate case proceeding. The testimony also included support for a proposed revenue adjustment mechanism.
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization

Sponsor	Date	Docket No.	Subject
			mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Nevada Public Utilities Commission			
Southwest Gas Corporation	09/21	Docket No. 21-09001	Sponsored testimony supporting the class cost of service,rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Southwest Gas Corporation	02/20	Docket No. 20-02023	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
New Hampshire Public Utilities Commission			
Unitil (Northern Utilities, Inc.)	8/21	Docket No. DG 21-104	Sponsored testimony supporting a revenue decoupling mechanism.
Unitil Energy Systems, Inc.	4/21	Docket No. DE 21-030	Sponsored testimony supporting a revenue decoupling mechanism.
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
New Jersey Board of Public Utilities			
South Jersey Gas Company	04/22	Docket No. GR22040253	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	12/21	Docket No. GR21121254	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
South Jersey Gas Company	03/20	Docket No. GR20030243	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Corporation Commission of Oklahoma			
The Empire District Electric Company	02/21	Cause No. PUD 202100163	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The proposed rate design included a three-year phase-in of the proposed rate increase.
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.

Sponsor	Date	Docket No.	Subject
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
Texas Gas Service Company – West Texas, North Texas, and Borger/ Skellytown Service Areas	06/22	Case No. 00009896	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Central Texas and Gulf Coast Service Areas	12/19	GUD No. 10928	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Beaumont/ East Texas Division	11/19	GUD No. 10920	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Borger/ Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
Virginia State Corporation Commission			
Rappahannock Electric Cooperative	10/22	Case No. PUR-2022-00160	Sponsored report and studies related to revenue requirements, class cost of service, rate design, and bill impact analysis for a streamlined application to increase base rates.

Sponsor	Date	Docket No.	Subject
American Electric Power - Appalachian Power Company	3/20	Case No. PUR-2020-00015	Sponsored testimony supporting the Lead/Lag study for the 2020 triennial review of base rates, terms, and conditions.
Nova Scotia Utility and Review Board			
Nova Scotia Power	01/22	Matter No. M10431	Sponsored evidence supporting the cash working capital requirement and lead/Lag study for a general rate case proceeding.
Ontario Energy Board			
Ontario Energy Association	01/21	Docket No. EB-2020-0133	Sponsored evidence regarding policies and ratemaking treatment related to COVID-19 costs in U.S. and Canadian regulatory jurisdictions. The evidence was used to support Ontario Energy Association's response to Staff's proposals

The Potomac Edison Company - Maryland
2021 Lead-Lag Study
Working Capital Requirement
Summary

Line	Description	Maryland Distribution Expenses	Average Daily Expenses	Revenue Lag	Ref.	Expense Lead	Ref.	(Lead)/Lag Days	Working Capital Requirement
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Operations and Maintenance Expenses**								
2	Energy Purchases	$ -	$ -	40.56	A	(22.33)	B	18.22	$ -
3	Payroll	-	-	40.56	A	(29.72)	C	10.84	-
4	Benefits	-	-	40.56	A	(36.90)	C	3.66	-
5	Pension and OPEB	-	-	40.56	A	0.00	C	40.56	-
6	Annual PSC Assessment	-	-	40.56	A	34.02	C	74.58	-
7	Service Company	-	-	40.56	A	(16.80)	C	23.76	-
8	Uncollectibles	-	-	40.56	A	0.00	C	40.56	-
9	Other O&M Expenses	-	-	40.56	A	(27.79)	C	12.77	-
10	**Total O&M Expenses**	$ -	$ -						$ -
11	**Income Taxes**								
12	Federal Income Taxes	$ -	$ -	40.56	A	(37.00)	D	3.56	$ -
13	State Income Taxes	-	-	40.56	A	(37.00)	D	3.56	-
14	**Total Income Taxes**	$ -	$ -						$ -
15	**Taxes Other Than Income Taxes**								
16	Payroll Taxes	$ -	$ -	40.56	A	(31.46)	E	9.10	$ -
17	Property Taxes	-	-	40.56	A	56.74	E	97.29	-
18	Gross Receipts Taxes	-	-	40.56	A	(54.00)	E	(13.44)	-
19	KWH Taxes	-	-	40.56	A	(37.86)	E	2.70	-
20	Sales and Use Tax	-	-	40.56	A	(27.90)	E	12.65	-
21	**Total Taxes Other Than Income Taxes**	$ -	$ -						$ -
22	**Interest Expense**								
23	Interest on Long-Term Debt	$ -	$ -	40.56	A	(92.82)	F	(52.27)	$ -
24	Interest on Customer Deposits	-	-	40.56	A	(240.52)	F	(199.96)	-
25	**Total Interest Expense**	$ -	$ -						$ -
26	**Cash Working Capital Requirement**	$ -	$ -						$ -

The Potomac Edison Company - Maryland
2021 Lead-Lag Study
Revenue Lag

Line	Description	Maryland Distribution	(Lead)/Lag Days	Reference	Dollar Days
1	Retail Electric Revenues	$ 500,062,082	40.81	WP A-1	$ 20,406,283,396
2	Other Revenues	3,530,510	4.98	WP A-4	17,595,436
3	Total Operating Revenues	$ 503,592,592	40.56		$ 20,423,878,831

The Potomac Edison Company - Maryland
2021 Lead-Lag Study
Energy Purchases

Line	Description	Payments	(Lead)/ Lag Days	Dollar Days	Reference
1	Energy Purchases	$ 348,863,804	(22.33)	$ (7,790,754,368)	Workpaper (B) - Energy Purchases
2	Total	$ 348,863,804	(22.33)	$ (7,790,754,368)	

The Potomac Edison Company - Maryland
2021 Lead-Lag Study
O&M Expenses Summary

Line	Description	(Lead)/Lag Days	Reference
1	Payroll	(29.72)	WP C-1
2	Benefits	(36.90)	WP C-3
3	Pension and OPEB	-	
4	Annual PSC Assessment	34.02	WP C-4
5	Service Company	(16.80)	WP C-5
6	Uncollectibles	-	
7	Other O&M Expenses	(27.79)	WP C-6

The Potomac Edison Company - Maryland
2021 Lead-Lag Study
Income Taxes

Line	Description	(Lead)/Lag Days
1	Income Taxes	
2	Federal Income Taxes	(37.00)
3	State Income Taxes	(37.00)

The Potomac Edison Company - Maryland
2021 Lead-Lag Study
Taxes Other Than Income Taxes

Line	Description	Expense	(Lead)/Lag Days	Reference	Dollar Days
1	Payroll Taxes				
2	FICA	$ 4,281,473	(31.49)	E-1	$ (134,826,360)
3	Federal Unemployment	23,854	(30.00)	E-2	(715,580)
4	State Unemployment	78,085	(30.00)	E-3	(2,342,201)
5	Payroll Taxes	$ 4,383,412	(31.46)		$ (137,884,140)
6	Property Taxes		56.74	E-4	
7	Gross Receipts Taxes		(54.00)	E-5	
8	KWH Taxes		(37.86)	E-6	
9	Sales and Use Tax		(27.90)	E-7	

The Potomac Edison Company - Maryland
2021 Lead-Lag Study
Interest Expense

Line	Description	(Lead)/Lag Days	Ref.
1	Long-Term Debt	(92.82)	H-1
2	Interest on Customer Deposits	(240.52)	H-2

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application Of The Potomac Edison Company For Adjustments to its Retail Rates for the Distribution of Electric Energy	* * * * *	Case No. ____

DIRECT TESTIMONY OF

TIMOTHY S. LYONS

Concerning: Class Cost of Service Study; Rate Design

March 22, 2023

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Timothy S. Lyons. My business address is 3 Speen Street, Suite 150, Framingham, Massachusetts 01701.

Q. Please describe your current position.

A. I am a Partner at ScottMadden, Inc. ("ScottMadden").

Q. Please describe your work experience.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held several management consulting positions in the energy industry, first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden in 2016.

Q. Please describe your educational background.

A. I hold a bachelor's degree from St. Anselm College, a master's degree in Economics from The Pennsylvania State University, and a master's degree in Business Administration from Babson College.

Q. Have you previously sponsored testimony before the Maryland Public Service Commission ("Commission")?

A. Yes. A summary of my testimony experience is included in Exhibit TSL-1.

Q. **What is the purpose of your Direct Testimony?**

A. The purpose of my Direct Testimony is to sponsor the proposed electric distribution rates in Maryland on behalf of The Potomac Edison Company ("PE" or the "Company"), a subsidiary of FirstEnergy Corp. ("FirstEnergy"). My Direct Testimony includes: (a) a description of the current rate classes; (b) development of the Class Cost of Service ("CCOS") study; and (c) development of the proposed revenue targets, rate design, and bill impact analyses for each rate class. The CCOS study was used as a guide to develop the proposed electric distribution rates.

The Direct Testimony also describes development of two CCOS studies.

- The first CCOS study was prepared generally consistent with methodologies used in the Company's most recent base rate case filing ("Case No. 9490"), except as noted below including modifications based on the Commission's order in Case No. 9490, the Company's most recent base rate case filing. The first CCOS study classifies distribution plant (Accounts 364 through 368) as customer and demand, as explained below.
- The second CCOS study ("Alternative CCOS study") is identical to the first CCOS study except the second CCOS study classifies distribution plant (Accounts 364 through 368) as demand.

Q. Are you sponsoring exhibits in connection with your testimony?

A. Yes. I am sponsoring the following exhibits that were prepared by me or under my direction:

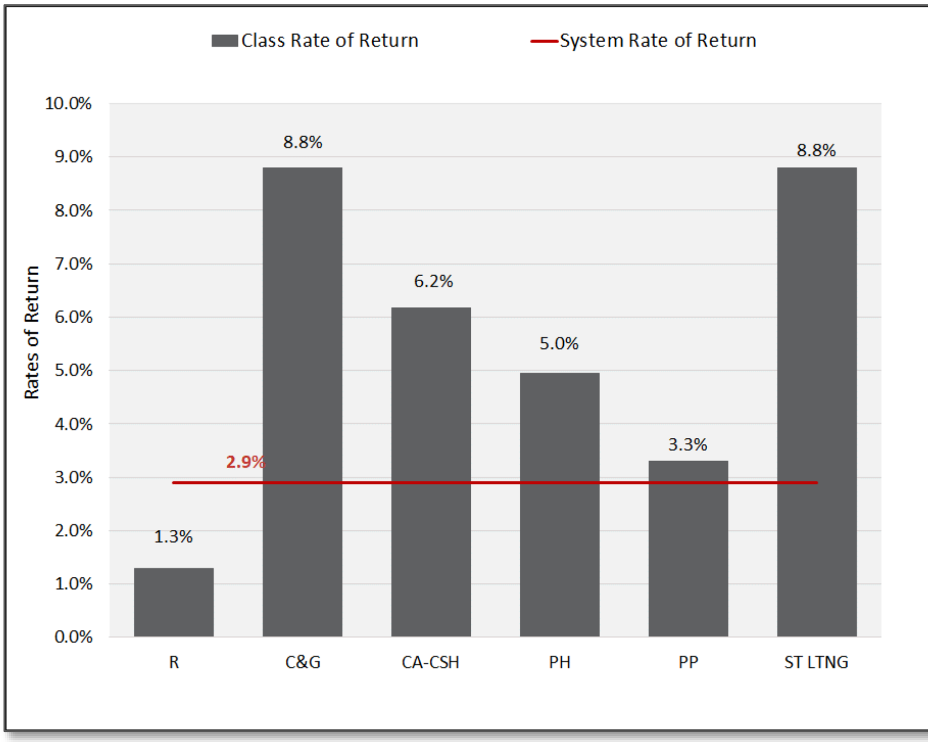
- Exhibit TSL-1 – Qualifications
- Exhibit TSL-2 – Summary of CCOS study
- Exhibit TSL-3 – Summary of rate design and bill impact analysis
- Exhibit TSL-4 – Summary of Alternative CCOS study
- Exhibit TSL-5 – 2019-2021 Demands

II. OVERVIEW

Q. Please summarize your Direct Testimony.

A. The results of the Company's CCOS study show differences in class rates of return ("ROR") at current base rates for each rate class as compared to the system or overall ROR, as shown in Figure 1 (below).

Figure 1: CCOS Study Results



The Figure compares class RORs to the system or overall ROR at current base rates.

The Figure shows the Residential (Schedule "R") rate class produces an ROR below the system ROR. The Figure also shows the General and Commercial Service (Schedules "C" and "G", collectively "C&G"),[1] General Service – All Electric (Schedule "C-A", including the church and school heating ("CSH") subset), Power Service (Schedule "PH"),[2] Large Power Service ("Schedule "PP"), and Street and Area Outdoor Lighting (Schedules "EMU", "MU", "EM", "LED", "OL", "AL", and "MSL", collectively "STLTNG") rate

[1] Special lighting contracts for the City of Hagerstown and City of Frederick are included in Schedules C&G for purposes of developing the CCOS study.
[2] Alternative Generation Schedule (Schedule AGS) is included in Schedule PH for purposes of developing the CCOS study.

classes produce RORs above the system ROR. The Company's CCOS study was prepared generally consistent with methodologies used in the Company's most recent base rate case filing in Case No. 9490, except as noted below including modifications related to the Commission's order in Case No. 9490.

The results of the CCOS study support a movement toward a more equitable rate structure where class RORs move closer to the system ROR. However, the proposed movement to the system ROR was subject to certain limitations to address customer bill impact considerations.

The proposed distribution base rates reflect three important rate design principles: (a) rates should recover the overall cost of providing service; (b) rates should be fair, minimizing inter- and intra-class inequities to the extent possible; and (c) rate changes should be tempered by rate continuity concerns.

The proposed rate design generally reflects a uniform increase in kilowatt-hour ("kWh") usage charges and kilowatt ("kW") demand charges following increases in the customer charges.

The Company prepared a bill impact analysis to evaluate the impact of the proposed base rate changes. The bill impact analysis evaluated a wide range of customer usage. The bill impact analysis was prepared in two ways:

1. Proposed base rates compared to current base rates; and

2. Proposed total bill that includes proposed base rates plus other charges compared to current base rates plus other charges.[3]

Overall, the proposed base rates will increase a monthly bill for a Residential customer using 1,000 kWh per month by $9.18 per month, or 9.3 percent prior to the proposed rate increment for new low-income residential assistance programs as discussed by Company witness Valdes and presented in the tariff exhibits presented by Company witness Fall. Inclusive of the proposed 32 cent rate increment, the proposed base rates will increase a monthly bill for a Residential customer using 1,000 kWh per month by $9.50 per month, or 9.7 percent.

Q. Did the Company's CCOS study address the Commission's directives from the prior base rate case in Case No. 9490?

A. Yes. The Company's CCOS study addressed the Commission's directives from the Company's prior base rate case in Case No. 9490, as summarized in Figure 2 (below).

Figure 2: The Company's Response to Commission Directives

Commission Directive[4]	Update to the CCOS Study
"Specifically, the Commission directs that, in conjunction with its next base rate case, Potomac Edison file updated studies utilized in both the JCOSS and the CCOSS, such that all updated studies are current to within one year of	The Company has updated supporting studies in the CCOS study to be based on data within one year of the test year.

[3] Other charges which are not part of distribution base rates include: Standard Offer Service Transmission and Electric Supply (Generation), Universal Service Program Surcharge, Cogeneration PURPA Project Surcharge, Franchise Tax Surcharge, Maryland Environmental Surcharge, EmPower MD Surcharge, Electric Distribution Investment Surcharge, and Administrative Credit.
[4] Case No. 9490, Order No. 89072 (Issued: March 22, 2019), at 97-98

Commission Directive[4]	Update to the CCOS Study
the test year in the Company's next base rate case."	
"Moreover, if Potomac Edison files a zero intercept study in its next rate case, the Company is directed to also submit a COSS without a zero intercept study, to enable consideration of the appropriateness of using such a study to allocate costs for Potomac Edison's service territory."	The Company has developed and filed an alternative version of the CCOS study without a zero-intercept study. The alternative study results are included as Exhibit TSL-4.
"The Company is also required to provide a COSS in its next base rate case that includes a labor allocator to better reflect the functionalization of general and intangible plant and to be more consistent with cost causation."	The Company's CCOS study includes a labor allocator to reflect functionalization of general and intangible plant.
"The Company is also directed in its next rate case to submit testimony supporting or rejecting the use of the ACP methodology to allocate costs related to subtransmission and FERC Accounts 362 and 368 capacitors based on current system conditions and cost causation."	The Company's testimony describes rationale for the ACP methodology.
"Finally, Potomac Edison is required in its next rate case to provide three years of demand at transmission, subtransmission, primary, and secondary levels, as well as their resulting allocators that are used in the COSS."	The Company has included 2019-2021 coincident peak demands as Exhibit TSL-5.

Q. Please describe the Company's service classifications.

A. The Company provides electric service to approximately 285,000 residential, commercial and industrial ("C&I"), and lighting customers, as shown in Figure 3 (below).

Figure 3: Test Year Customers and Sales

Rate Class	Number of Customers	% of Customers	Sales kWh	% of Sales	kWh usage per Customer
Residential (R)	250,592	88.04%	3,349,359,320	49.16%	13,366
General and Commercial (C & G)	31,204	10.96%	905,501,412	13.29%	29,018
General Service - All Electric (C-A)	327	0.11%	23,294,131	0.34%	71,269
Power Service (PH)	1,682	0.59%	1,802,181,245	26.45%	1,071,717
Large Power Service (PP)	10	0.00%	709,402,478	10.41%	70,353,965
Lighting (STLTNG)	809	0.28%	23,391,160	0.34%	28,920
Total	284,623	100.00%	6,813,129,746	100.00%	23,937

The Figure shows that during 2022 the Company served, on average, 250,592 Residential ("R") customers (88.0 percent), 31,204 General and Commercial Service ("C&G") customers (11.0 percent), 327 General Service – All Electric ("C-A") customers (0.1 percent), 1,682 Power Service ("PH") customers (0.6 percent), 10 Large Power Service ("PP") customers, and 809 Lighting ("STLNG") customers (0.3 percent).

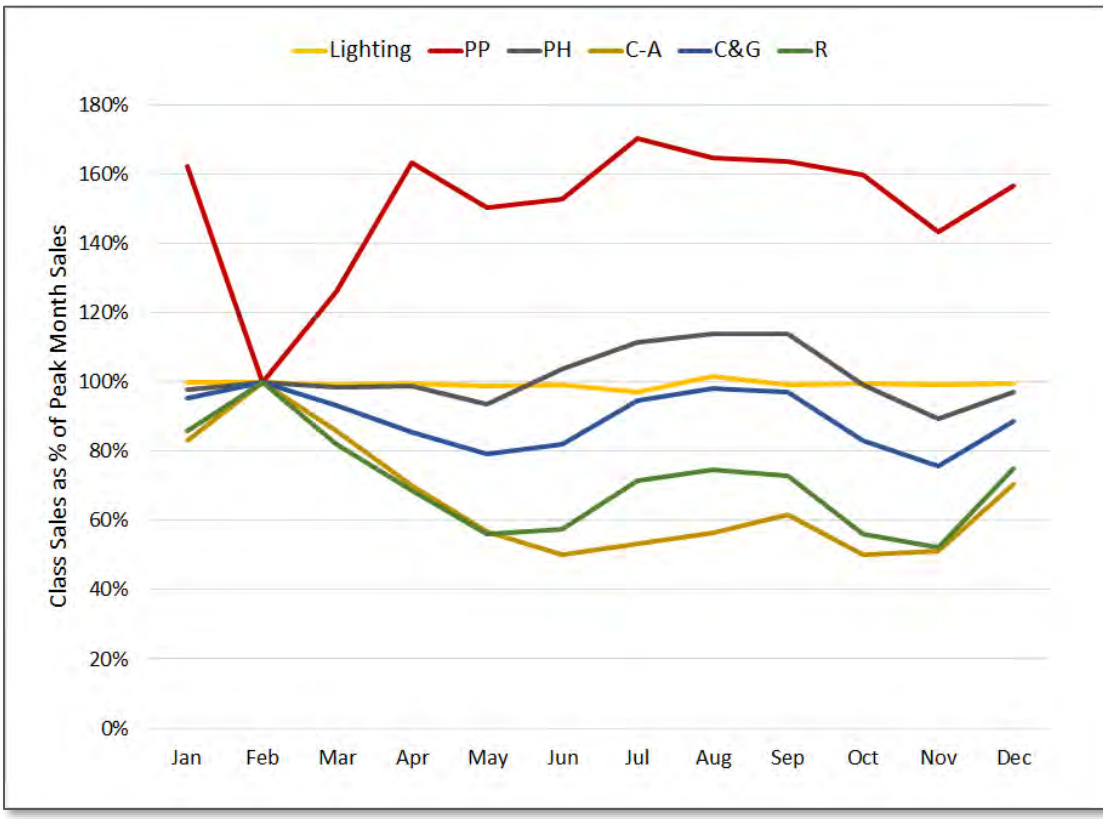
Q. Please describe the characteristics of the service classifications

A. Figure 3 (above) provides a breakdown of test year customers and kWh sales by rate class. The test year is based on the period January 1, 2022 through December 31, 2022.

The Figure shows the Residential rate class represents a majority (88.0 percent) of the Company's customers. The Figure also shows variations in annual use per customer among the rate classes. Residential customers, for example, use on average 13,366 kWh per year, while Large Power Service customers use on average 70,353,965 kWh per year.

Figure 4 (below) shows monthly kWh sales by rate class as a percentage of system peak month (February) sales for that rate class. The Figure shows sales vary seasonally for certain rate classes.

Figure 4: Monthly kWh Sales as % of System Peak Month (February)



The Residential rate class, for example, shows a seasonal load pattern, with monthly sales increasing during the winter and summer months, reflecting heating and cooling use, respectively. The General Service and Power Service rate classes show a relatively consistent load pattern throughout the year, with slight increases during the summer months. The Lighting rate classes show a relatively consistent load pattern throughout the year. Load pattern differences, as discussed below, have implications on the allocation of costs in the CCOS study.

Q. Please describe the Company's current rate structure.

A. The Company's current rate structure consists of base rates and rider charges.[5] The base rates include monthly customer charges, usage (kWh) charges, and demand (kW) charges.

III. <u>ALLOCATED COST OF SERVICE STUDY</u>

Q. What is the purpose of a CCOS study?

A. The purpose of a CCOS study is to allocate a utility's overall cost of service to each rate class in a manner that reflects its underlying cost of service. This approach is well established in industry literature.[6]

Q. What was the approach used to develop the CCOS study for this case?

A. The approach used to develop the CCOS study for this case was based on three steps. First, costs were functionalized or assigned into functional categories. Next, functionalized costs were classified into one of three cost drivers, based on whether the costs are related to: (1) serving peak demands, (2) serving energy demands, or (3) meeting customer service requirements. Finally, classified costs were allocated to each rate class based on methods that best reflect how the costs were incurred.

[5] The Company's tariffs are available at: https://www.firstenergycorp.com/customer_choice/maryland/maryland_tariffs.html.
[6] See Principles of Public Utility Rates by James C. Bonbright

The three steps were performed using two types of assignments: direct assignment and indirect assignment. Direct assignments utilized the Company's financial data and certain assignments of plant investments and expenses to certain functions, classifications, and rate classes. Indirect assignments utilized composite allocators based on direct and indirect assignments developed during the functionalization, classification, and allocation process. The three steps were utilized to prepare the two CCOS studies.

- The first CCOS study was prepared generally consistent with methodologies used in the Company's most recent base rate case filing ("Case No. 9490"), except as noted below including modifications related to the Commission's order in Case No. 9490, the Company's most recent base rate case filing. The first CCOS study classified distribution plant (Accounts 364 through 368) as customer and demand, as explained below.
- The second or Alternative CCOS study is identical to the first CCOS study except the Alternative CCOS study classified distribution plant accounts (Accounts 364 through 368) as demand.

Q. What is functionalization?

A. Functionalization is the process of assigning rate base and expense items into operational components. The functionalization of costs in the CCOS study was based on the Company's accounting records, which are maintained in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA").

Q. What is classification?

A. Classification is the process of assigning rate base and expense items into categories that reflect cost-causation. There are three principle causes or drivers of costs related to the electric system:

- Customer-related – costs that vary with the number of customers, such as costs associated with connecting customers to the electric system and providing basic customer services, such as metering and billing;
- Demand-related – costs that vary with maximum customer demands at the time of the system peak, at the time of the rate class peak, or at the time of the individual customer peak; and
- Energy-related – costs that vary with production, transmission, and/or delivery of energy, such as fuel and purchased power expenses.[7]

Q. What is allocation?

A. Allocation is the process of assigning rate base and expense items to each rate class based on allocators that best reflect how the costs were incurred. In other words, cost allocation should follow how costs were incurred.

Q. What types of allocators were used to develop the CCOS study?

A. There were three types of allocators used to develop the CCOS study:

1. Class determinants – class characteristics, such as number of customers, peak demands, kWh sales, and revenues by rate class;

[7] The CCOS study classified costs as customer or demand since the CCOS study reflects only distribution costs. The primary drivers of distribution costs are customers and demands.

2. Special studies – detailed analysis of specific plant or expense items, such as meters and services; and
3. Indirect – composite allocators based on how other costs were allocated.

Q. What was the approach used to develop the CCOS study for this case?

A. The CCOS study was based on a spreadsheet model developed by ScottMadden for this filing. Rate base and expense items in the CCOS study were assigned to each rate class based on the three-step process described above. The results of the CCOS study are shown in Figure 1 (above).

Q. What conclusions can be reached when a rate class ROR is lower or higher than the system or overall ROR?

A. If a rate class produces a ROR that is lower than the system ROR, then the revenues recovered from the rate class are less than its cost of service. Conversely, if a rate class produces a ROR that is higher than the system ROR, then the revenues recovered from the rate class are more than its cost of service. As discussed below, the CCOS study results were used to establish revenue targets for each rate class, subject to bill continuity concerns, that move the Company's proposed rates in aggregate closer to the system ROR to achieve more fair and equitable rates across customer classes.

Q. What data was used to prepare the CCOS study?

A. The CCOS study was based on test year data for the period January 1, 2022 through December 31, 2022. The CCOS study includes the number of customers, sales, and revenues by rate class. The CCOS study also includes rate base items, including intangible plant, sub-transmission, distribution, and general plant-in-service as well as (a) additions to rate base, such as working capital and (b) reductions to rate base, such as accumulated depreciation. The CCOS study also includes operations and maintenance ("O&M") expenses, including distribution, customer service, customer account, sales, and administrative and general expenses as well as taxes other than income, such as payroll and property taxes, and income taxes.

Q. What was the approach to functionalize costs in the CCOS study?

A. As discussed earlier, functionalization is an important first step in development of the CCOS study. The functionalization process in this study generally followed the USOA. However, distribution plant was further functionalized into primary and secondary distribution facilities to ensure that the cost of service at these functional levels was separately identified and applied.

The overall cost of service was functionalized into one of the following categories:

- Sub-transmission – plant investment and expenses associated with the Company's sub-transmission facilities. These include sub-transmission plant, accumulated depreciation, and depreciation expense.
- Primary Distribution – plant investment and expenses associated with the Company's primary voltage distribution facilities. These include primary distribution plant, accumulated depreciation, depreciation expense, and related O&M expenses. Some costs that support both the primary and secondary distribution systems were functionalized into primary and secondary functions.

Such costs include poles and towers, overhead conductors and devices, underground conduit, underground conductors and devices, and transformers.

- Secondary Distribution – plant investment and expenses associated with the Company's secondary voltage distribution facilities. These include secondary distribution plant, accumulated depreciation, depreciation expense, and related O&M expenses. The secondary portion of poles and towers, overhead conductors and devices, underground conduit, underground conductors and devices, and transformers are also included in this function.
- Customer Service – plant investment and expenses associated with the Company's customer service facilities. These costs are largely related to customer service, customer accounts, and sales expenses.

The remaining rate base and cost of service accounts were assigned to one of the functional categories based on composite functionalization of the plant accounts. For example, general plant and labor-related administrative and general ("A&G") expenses were assigned to the functional categories based on the composite functionalization of labor-related sub-transmission, and distribution expenses.

In addition, the distribution O&M expenses were assigned to one of the functional categories based on functionalization of the relevant distribution plant accounts. For example, the overhead line O&M costs (Account 583) was functionalized based on overhead plant (Account 365). The approach to functionalize distribution O&M expenses is a refinement to the Company's CCOS study filed in the most recent base rate case.

Q. What was the approach to classify costs in the CCOS study?

A. The CCOS study classified costs into one of the following three categories:

- Customer – costs associated with providing customer access to the electric system as well as providing on-going customer services, such as meter reading and billing services.
- Demand – costs associated with meeting customer peak demand requirements.
- Energy – costs associated with meeting customer energy requirements.

Q. What was the approach to classify sub-transmission plant?

A. Sub-transmission plant was classified as demand since the facilities are used to meet demand requirements.

Q. What was the general approach to classify distribution plant?

A. Distribution plant represents the largest portion of the Company's investment in utility plant. Distribution plant was classified based on specific functions. For example, distribution plant related to facilities associated with distribution substations (Account 362) was classified based on demand since substations are generally designed based on peak demands of customers served from the substation.

Q. What was the approach to classify distribution plant related to overhead and underground lines (Accounts 364-368)?

A. Classification of distribution plant related to overhead and underground lines (Accounts 364-368) reflected two primary cost drivers. The first cost driver is the number of customers, i.e., distribution facilities are designed to provide customer access to the electric system. The second driver is peak demands, i.e., distribution facilities are designed to meet customer peak demands throughout the year. This approach to classification of distribution facilities is well-established and recognized by the National Association of Regulatory Commissioners ("NARUC"). Specifically, NARUC states,

> "Distribution plant accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services and meters are directly related to the number of customers on the utility's system…each primary plant account can be separately classified into demand and customer components"[8]

The classification of distribution plant (Accounts 364-368) in this study is consistent with the approach described in the NARUC manual as well as the approach in Case No. 9490. Specifically, distribution plant (Accounts 364-368) is classified based on the zero- or minimum-intercept method.

Q. What is the zero- or minimum-intercept method?

A. The zero- or minimum-intercept method represents the cost of connecting customers to the system with a hypothetical "zero size" facility. The method includes a regression analysis conducted to examine the relationship between the facility sizes and their average costs. The intercept of the regression equation represents the average cost of a hypothetical zero

[8] NARUC Electric Utility Cost Allocation Manual, Pg. 90

size facility. The "zero size" facility costs are classified as customer-related, while distribution plant in excess reflects the cost of serving customer peak demands and is classified as demand-related. The approach is described in the NARUC manual:

> The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation…. The technique is related to installed cost to current carrying capacity or demand rating, creating a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component.[9]

Q. How was the zero-intercept method used to classify distribution plant (Accounts 364-368)?

A. The Company performed a regression of distribution plant (Accounts 364-368) facility sizes on their respective average costs. The intercept of the regression equation represents the average cost of a hypothetical zero size facility. The "zero size" facility costs are classified as customer, while the remaining costs are classified as demand. The method generally utilized current costs for each plant account or installed costs adjusted for current dollars utilizing the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman").

Q. How was distribution plant (Accounts 364-368) classified based on the zero-intercept method?

[9] Id. at p. 92.

A. Classification of distribution plant (Accounts 364-368) is summarized below.

- Poles, Towers, and Fixtures (Account 364). The Company's zero-intercept study resulted in 27.05 percent and 31.73 percent of primary and secondary costs, respectively, classified as customer with the remaining portion classified as demand.
- Overhead conductors and devices (Account 365). The Company's zero-intercept study resulted in 43.36 percent and 69.04 percent of primary and secondary costs, respectively, classified as customer with the remaining portion classified as demand.
- Underground Conduits (Account 366). The Company classified primary and secondary costs, respectively, as demand since the Company installs underground conduit for purposes of serving customer demands and not to connect customers to the electric grid.
- Underground Conductors and Devices (Account 367). The Company's zero-intercept study resulted in 49.92 percent and 80.25 percent of primary and secondary costs, respectively, classified as customer with the remaining portion classified as demand.
- Line Transformers (Account 368). The Company's zero-intercept study resulted in 29.79 percent and 75.35 percent of primary and secondary costs, respectively, classified as customer with the remaining portion classified as demand.
- Services (Account 369). Service plant was classified as customer.

- Meters (Account 370). Meter plant was classified as customer.

Q. How were other plant items classified?

A. Other plant items were similarly classified based on their underlying cost drivers. Rate base items not directly associated with one of the classification categories, such as intangible plant, were classified through a composite classifier based on the classification of labor expenses.

Q. Please discuss the classification of O&M expenses.

A. Distribution O&M expenses were classified in a manner similar to the respective plant items. For example, distribution O&M expenses followed the classification of their respective plant accounts. Classification of overhead line O&M costs (Account 583) was based on classification of overhead plant (Account 365). The classification of distribution O&M expenses is a refinement to the Company's CCOS study filed in the most recent base rate case proceeding.

O&M expense items not directly associated with one of the classification categories, such as non-labor related A&G expenses, were classified through a composite classifier based on related costs.

Q. Please describe the allocation process used in developing the CCOS study.

A. Costs were allocated to each rate class based on how costs are incurred to serve that class. In other words, for each component of cost, the Company developed an allocator that best reflected how costs are incurred.

Q. Please describe the allocators used in developing the CCOS study.

A. The CCOS study was based on three types of allocators:

- Class determinants – class characteristics, such as number of customers, peak demands, kWh sales, and revenues by rate class;
- Special studies – detailed analysis of specific plant or expense items, such as meters and uncollectible expenses; and
- Indirect – composite allocators based on how other costs are allocated.

Q. How was sub-transmission plant and FERC accounts 362 and 368 capacitors allocated?

A. Sub-transmission plant and FERC accounts 362 and 368 capacitors were allocated to each rate class consistent with their design objectives to meet peak demand requirements throughout the year. Specifically, sub-transmission and capacitors plant were allocated to each rate class based on the Average Coincident Peak ("ACP") method, which is derived as the average of twelve-monthly coincident peaks. The approach is consistent with the Company's prior approach, which has been accepted by the Commission. The ACP method is recognized by NARUC.[10]

Q. How was distribution demand plant allocated?

A. Distribution demand plant was allocated to each rate class consistent with its design objectives to adequately serve local area loads since distribution circuits and transformers are designed to serve specific customers or groups of customers. Specifically, distribution demand plant was allocated to each rate class based on Non-Coincident Peak ("NCP")

[10] NARUC Electric Utility Cost Allocation Manual, Pg. 79

customer peak demands, which is derived as the maximum of twelve-monthly non-coincident peaks.

Q. How was meter plant allocated?

A. Meter plant was allocated based on the results of a study that reflects the current cost of meters in each rate class. The meter study complies with the Commission's directive from the Company's prior base rate case in Case No. 9490, as described in Figure 2 (above). The allocator reflects the Company's estimated cost of meter and meter installation for each rate class.

Q. Please describe the process to develop the composite allocators.

A. There are several composite allocators developed internally based on the allocation of various plant investments and expenses. These are used to allocate cost items that cannot be readily categorized. For example, general plant is allocated based on the composite allocation of all labor-related sub-transmission, distribution, customer accounts, and customer service O&M expenses. This approach is recognized in industry literature[11] and is generally consistent with the methodologies described in the Company's prior base rate case filing.

Q. How were O&M expenses allocated to each rate class?

A. O&M expenses were allocated to each rate class consistent with their respective plant accounts. For example, allocation of overhead line O&M costs (Account 583) was based on allocation of overhead plant (Account 365). The approach to allocation of distribution

[11] NARUC Electric Utility Cost Allocation Manual, Pg. 105

O&M expenses is a refinement to the Company's CCOS study filed in its most recent base rate case.

Q. Does the cost of service vary across the Company's rate classes?

A. Yes, the cost of service per customer and per kWh (i.e., unit cost of service) varies across the Company's rate classes, as shown in Figure 5 (below).

Figure 5: Unit Cost of Service by Rate Class

	Revenue Requirements			
Rate Class		Per Customer		Per kWh
Residential (R)	$	488	$	0.036
General and Commercial (C, G, Hag&Fred)		665		0.023
General Service (CA, CSH)		1,290		0.018
Power Service (PH, AGS)		10,886		0.010
Large Power Service (PP)		139,005		0.002
Lighting (STLTNG)		5,490		0.190

The Figure shows, for example, the unit cost of service for the Residential rate class is $488 per customer, while the unit cost of service for the PP rate class is $139,005 per customer. By comparison, the unit cost of service for the Residential rate class is $0.036 per kWh, while the unit cost of service for the PP rate class is $0.002 per kWh.

Q. How are variations in the unit cost of service used to support the Company's rate design?

A. Variations in the unit cost of service support the need for distinct rate classes and rate designs.

IV. OVERVIEW OF RATE DESIGN

Q. Please describe the principles used to guide the proposed rate design.

A. The proposed rate design was guided by several principles commonly used throughout the industry, including: (a) rates should recover the overall cost of providing service; (b) rates should be fair, minimizing inter- and intra-class inequities to the extent possible; and (c) rate changes should be tempered by rate continuity concerns.[12]

Because these principles can conflict, the proposed rate design reflects a level of judgment to balance these principles.

Q. How were these principles applied in this proceeding?

A. First, rates were designed to recover the overall cost of service. This was done by developing customer, demand, and energy charges based on test year bills, kW billing demands and kWh sales. In addition, rates were designed to be fair and equitable. This was done by setting revenue targets for each rate class that reflect in aggregate a movement toward the system ROR based on the results of the CCOS study. Specifically, the results of the CCOS study show that some rate classes produce a ROR that is less than the overall ROR. The proposed rate design reduces that difference by proposing rate increases for certain rate classes that are higher than the system average. Another rate design objective

[12] See Bonbright, James, Danielsen, Albert, and Kamerschen, David. "Principles of Public Utility Rates." Public Utilities Reports, Inc. pp. 377-407 (2nd Ed. 1988).

is to moderate rate changes to address rate continuity concerns. This objective was considered while setting revenue targets and then again while setting rate elements.

Q. Please summarize the steps taken to develop the proposed rates.

A. The first step to develop the proposed rates was to establish the overall revenue requirement to be recovered from base distribution rates. The next step was to set revenue targets for each rate class based on the results of the CCOS study, moderated by rate continuity concerns. Rates within each rate class were then designed to recover the revenue targets based on test year bills, kW demand, and kWh usage data.

Q. What is the total revenue requirement that you used as a starting point?

A. To determine the total revenue requirement, I relied on the overall cost of service presented in the testimony and exhibits of Company witness Soltis, which in Exhibit JAS-1 indicates an increase in the revenue requirement of $47.5 million. This equates to a total revenue requirement of $186.3 million when added to the existing $138.8 million of operating revenues.

Q. Please describe the process to set the revenue targets for each rate class.

A. Since each rate class currently produces a ROR that is different than the overall system ROR, the starting point for setting the revenue targets was to compare current class revenues to class revenues at equalized rates of return.

Q. In general, how did you determine the appropriate rate design within each rate class?

A. The proposed rates were designed by first ensuring the rates recover the proposed revenue target for each rate class. The proposed rates were then designed to reflect a uniform increase in sales (kWh) charges and demand (kW) charges following increases in customer charges.

V. PROPOSED RATE DESIGN

Q. Please describe the process used to set the revenue requirement targets for each rate class.

A. The starting point for setting the class revenue targets was first identifying the base rate changes necessary to achieve equalized rates of return for all rate classes. For those rate classes that produce a ROR less than the system ROR, the rate increases necessary to achieve equalized rates of return were higher relative to the system average; however, the movement to equalized rates of return for all rate classes was moderated by bill continuity concerns.

Specifically, to mitigate bill impact concerns the proposed revenue targets for each rate class were based on a 20.0 percent movement toward Equalized Rates of Return ("EROR"), as shown in Figure 6 (below).

Figure 6: Proposed Class Revenue Targets

The Potomac Edison Company (Maryland) Target Revenues	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
Revenue Requirements at EROR							
Delivery Revenues at EROR	167,686,930	122,365,061	20,761,563	419,160	18,309,580	1,390,045	4,441,521
Current Delivery Revenues	120,194,282	76,638,469	22,321,797	382,670	15,098,581	938,268	4,814,496
Increase / (Decrease) ($)	47,492,648	45,726,592	(1,560,234)	36,490	3,210,998	451,777	(372,975)
Increase / (Decrease) (%)	39.5%	59.7%	-7.0%	9.5%	21.3%	48.2%	-7.7%
Revenue Requirements at Uniform %							
Uniform Increase in Revenues	167,686,930	106,920,807	31,141,861	533,875	21,064,519	1,309,009	6,716,859
Current Retail Revenues	120,194,282	76,638,469	22,321,797	382,670	15,098,581	938,268	4,814,496
Increase	47,492,648	30,282,338	8,820,064	151,205	5,965,938	370,740	1,902,363
Increase (%)	39.5%	39.5%	39.5%	39.5%	39.5%	39.5%	39.5%
Movement to EROR	20.00%						
Revenue Targets							
Step 1: 20% Movement to EROR (excl. Lighting)	161,425,139	$ 110,009,658	$ 29,065,801	$ 510,932	$ 20,513,531	$ 1,325,216	
Step 2: Set Lighting at 2x Total Increase	5,688,019						$ 5,688,019
Step 3: Lighting Adjustment Assigned to Non-Res	573,772		$ 324,361	$ 5,702	$ 228,921	$ 14,789	
Adjusted Revenue Targets	167,686,930	$ 110,009,658	$ 29,390,162	$ 516,634	$ 20,742,452	$ 1,340,005	$ 5,688,019
Current Retail Revenues	120,194,282	76,638,469	22,321,797	382,670	15,098,581	938,268	4,814,496
Increase	47,492,648	33,371,189	7,068,365	133,964	5,643,871	401,736	873,523
Increase (%)	39.5%	43.5%	31.7%	35.0%	37.4%	42.8%	18.1%

Figure 6 shows revenue requirements for each rate class based on three approaches to setting class revenue targets: (1) a full movement to EROR, (2) a uniform increase in revenues, and (3) a partial movement to EROR, which is the Company's proposal. A full movement to EROR would result in a residential class distribution-only increase of 59.7 percent. A uniform increase would result in a residential class distribution-only increase of 39.5 percent, consistent with the overall revenue increase, but achieves no movement to EROR. The Company's proposed revenue targets reflect a partial movement to EROR of 20.0 percent.

The Company believes a 20.0 percent movement to EROR strikes an appropriate balance between moving to cost-based rates (full movement to EROR) and addressing rate continuity considerations (uniform increase in revenues).

Q. Please describe the process to set the proposed base rates for each rate class?

A. To mitigate bill impact concerns, the proposed rates for each rate class were generally based on a uniform increase in kWh sales and kW demand charges after increases in the customer charges.

Q. What are the proposed changes to Schedule R, the residential rate class?

A. The Company proposes to increase the residential customer charge from $5.70 per month to $8.00 per month, consistent with the underlying customer related costs as shown in Exhibit TSL-3. The class revenue requirement not recovered in the customer charge is recovered through a single-block kWh energy charge.

Q. What are the proposed changes to Schedules G and C, the general service rate class?

A. Schedules G and C are both general service rate schedules, with Schedule G available to all non-residential, non-streetlighting customers. Schedule C is designed to serve the same type of customers as those receiving service under Schedule G but was closed to new customers as of November 26, 1991. The primary difference between these two rate schedules is that Schedule C has a demand charge which is embedded in kWh energy rates by expanding the size of the second energy block based upon the magnitude of the kW demand, whereas Schedule G has a kW rate laid out separately from the kWh rate. Since these two rate schedules are intrinsically related, any change in rates to Schedule G results in a corresponding change in rates to Schedule C.

Although the underlying customer-related costs shown in Exhibit TSL-3 support a customer charge of $13.00 per month for general service rates Schedule G and C, the Company limited the increase in customer charges to no more than double the existing customer charge. This results in an increase in the customer charge from $4.00 per month to $8.00 per month, which helps to ensure all customers pay a minimum contribution to fixed costs. Exhibit TSL-3 shows calculation of customer costs that support the customer charge, which is applied equally to Schedules G, C, C-A and the CSH subset of Schedule C-A.

The same general rate design principles for Schedule G have been applied to Schedule C, with the rate of the first and third kWh energy blocks on Schedule C identical to the kWh energy rate for Schedule G. However, the rate for the second energy block for Schedule C is larger than the first and third kWh energy blocks since the second energy block embeds the pricing of demand which is tied to the kW demand rate for Schedule G.

Q. What are the proposed changes to Schedule C-A and the CSH subset?

A. Schedule C-A is an all-electric general service rate schedule, with the CSH subset for churches and schools with electric space heating. Schedule C-A and the CSH subset has been closed to new customers as of April 9, 1973.

Schedule C-A and the CSH subset have a customer charge identical to Schedules G and C to ensure the customers pay a minimum contribution to fixed costs. In addition, consistent with the distribution rates approved in the Company's last base rate case, the Schedules have a flat rate per kWh.

Q. What are the proposed changes to Schedule PH?

A. Schedule PH is available to all non-residential, non-streetlighting customers with demands of 50 kW or greater. The Company proposes to introduce a customer charge to recover customer-related costs. When customer charges for Schedules G, C, C-A and the CSH subset of Schedule C-A were introduced to the rate design in the Company's last base rate case, the approved value was approximately one-third of the value proposed by the Company and supported through the underlying customer related costs, Similarly, the Company has limited the new customer charge for Schedule PH to $17.00 per month, which is one-third of the underlying customer related costs. The minimum demand on Schedule PH is 50 kW, so the application of the pre-existing minimum demand to demand rates also results in a minimum contribution to fixed costs.

Q. What are the proposed changes to Schedule AGS?

A. Schedules AGS provides standby and maintenance power for customers with generating facilities, such as qualifying facilities as defined in the Public Utility Regulatory Policies Act of 1978.

The CCOS study results for Schedule AGS are included within Schedule PH; consequently, the two rate schedules share the same pro forma revenue percentage change and share the same pro forma rate design characteristics. The Company also proposes to introduce a customer charge to recover customer related costs, which is an identical $17.00 per month value from Schedule PH.

Q. What are the proposed changes to Schedules PP?

A. Schedule PP is a large power service rate schedule available to all non-residential, non-streetlighting customers with demands of 5,000 kW or greater and high-voltage service facilities.

Similar to the introduction of customer charges for Schedules G, C, C-A and the CSH subset of Schedule C-A during the Company's last base rate case, the Company has limited the new customer charge for Schedule PP to $453.00 per month, which is one-third of the underlying customer related costs. The minimum demand on Schedule PP is 5,000 kW, so the application of the pre-existing minimum demand to demand rates also results in a minimum contribution to fixed costs.

Q. What are the proposed changes to special streetlighting contracts?

A. The special lighting contracts are with the City of Hagerstown and the City of Frederick, whereby by the Company supplies secondary energy to streetlights and traffic signals. This service shares characteristics with general service Schedules G and C instead of the Company's streetlighting rate schedules since the customers are responsible to provide, install and maintain the lighting facilities beyond the point of service delivery by the Company.

The Company proposes to increase the kWh charges to recover the increase in class revenue targets. The Company does not propose to introduce a customer charge since the relatively constant usage ensures a minimum contribution to fixed costs.

Q. What are the proposed changes to streetlighting?

A. Three of the street lighting rate schedules are legacy rate schedules that are closed to new customers, with Schedules OL and MSL closed to new customers as of November 18, 1998, and Schedule AL closed to new customers as of September 9, 1985. The remaining street lighting rate schedules are available to all customers, with most customers gravitating to service under Schedules EMU and LED.

The pro forma change in revenue is collected as an equal percentage from all street lighting rates at a level necessary to collect the street lighting pro forma revenue increase, with the exception for long-term service. Long-term service remains as a 50 cent per light discount from its equivalent standard term service counterpart fixture.

Q. Have you examined the impact of your proposed changes in base rates on customers for each rate class?

A. Yes. The Company evaluated the customer bill impacts of the proposed base rate changes based on a range of annual usage within each rate class, as included in Exhibit TSL-3. The bill impact analysis was prepared in two ways:

1. Proposed base rates compared to current base rates; and
2. Proposed total bill that includes proposed base rates plus other charges compared to current total bill that includes current base rates plus other charges

Q. What is the monthly revenue impact on customers?

A. Figure 7 (below) shows the monthly bill impact on residential, commercial, and industrial rate classes. Please note, the amount provided below for residential Schedule R is prior to the proposed rate increment for new low-income residential assistance programs as discussed by Company witness Valdes and presented in the tariff exhibits presented by Company witness Fall.

Figure 7: Monthly Bill Impact by Rate Class

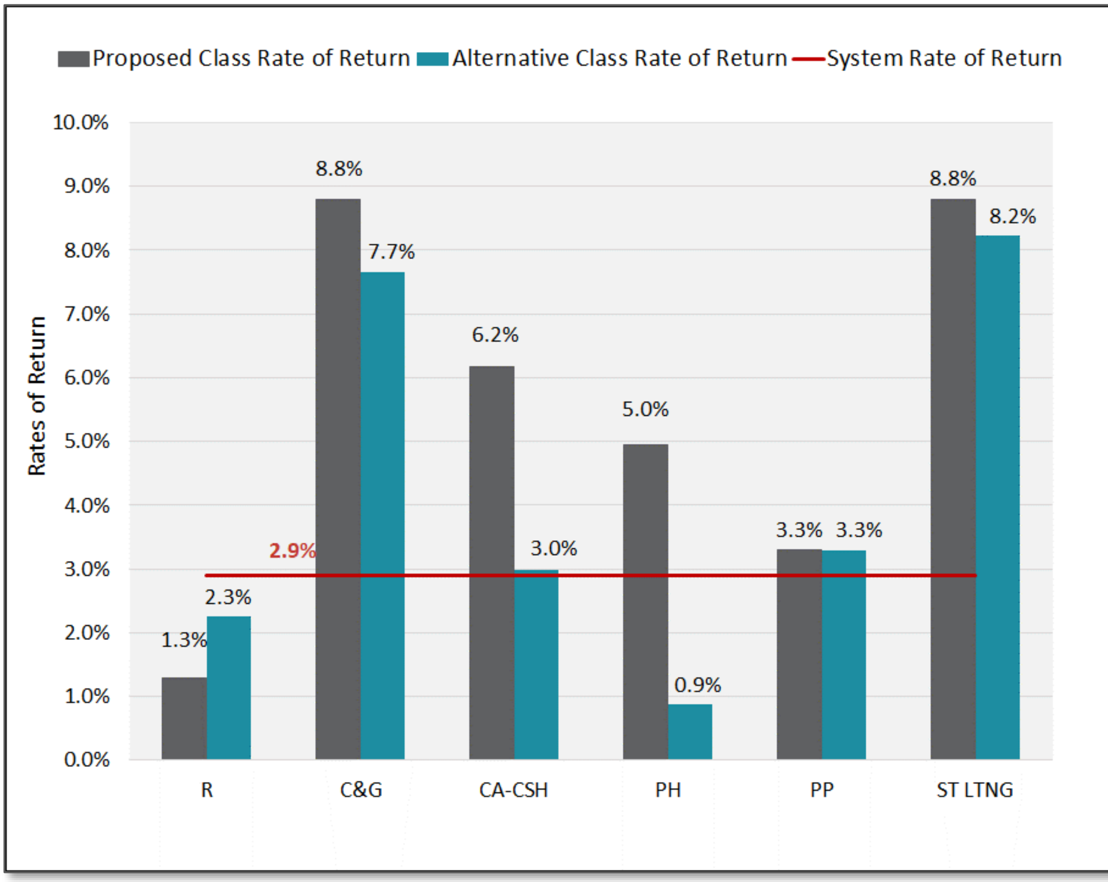
Rate Schedule	Average Monthly Usage	Proposed Monthly Bill	Current Monthly Bill	Increase / (Decrease) ($)	Increase / (Decrease) (%)
Total Rates					
R	1,000	$ 107.51	$ 98.33	$ 9.18	9.3%
C	2,400	$ 295.99	$ 276.46	$ 19.53	7.1%
G	2,400	$ 271.11	$ 253.15	$ 17.96	7.1%
C-A	5,100	$ 621.29	$ 590.95	$ 30.34	5.1%
CSH	7,500	$ 876.06	$ 848.81	$ 27.25	3.2%
PH	89,200	$ 8,373.42	$ 8,148.50	$ 224.92	2.8%
PP	5,850,000	$ 494,512.99	$ 491,286.66	$ 3,226.33	0.7%

VI. ALTERNATIVE CCOS STUDY

Q. Has the Company prepared an Alternative CCOS study?

A. Yes. Consistent with the Commission's directive in Case No. 9490, the Company's most recent base rate case, the Company has prepared an Alternative CCOS study that classifies distribution plant (Accounts 364-368) as demand. The results of the Alternative CCOS study are presented in Exhibit TSL-4 and summarized in Figure 8 (below). Although the Alternative CCOS was not used in the previously-discussed rate design, it is being provided in compliance with the Commission's directive, as described in Figure 2 (above).

Figure 8: Comparison of Proposed and Alternative CCOS Study



Q. **Does this conclude your Direct Testimony?**

A. Yes, it does.

Summary of Qualifications

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rates and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim served as Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony and evidence before 23 state regulatory commissions and 2 Canadian regulatory boards. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. from Babson College.

Areas of Specialization

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas

Capabilities

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
Cook Inlet Natural Gas Storage Alaska, LLC	7/21	Docket No. U-21-058	Sponsored testimony supporting the lead-lag study/cash working capital requirement for a general rate case proceeding.
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted and sponsored testimony supporting a lead-lag study for a general rate case proceeding.
Arizona Corporation Commission			
Southwest Gas Corporation	12/21	Docket No. G-01551A-21-0368	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (The Empire District Electric Company)	2/23	Docket No. 22-085-U	Sponsored testimony supporting the class cost of service, rate design, bill impact studies, and revenue decoupling for a general rate case proceeding.
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
California Public Utilities Commission			
Bear Valley Electric Service, Inc.	10/22	Application No. 22-08-010	Sponsored testimony supporting marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Liberty Utilities (CalPeco Electric)	5/21	Application No. 21-05-017	Sponsored testimony supporting the lead-lag study/cash working capital, marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Southwest Gas Corporation (Southern California, Northern California, and South Lake Tahoe jurisdictions)	8/19	Application No. 19-08-015	Sponsored testimony on behalf of three separate rate jurisdictions supporting revenue requirements, lead-lag/ cash working capital, and class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Illinois Commerce Commission			
Ameren Illinois Company d/b/a Ameren Illinois	1/23	Docket No. 22-0487	Sponsored testimony supporting a Multi-Year Integrated Grid Plan (Grid Plan). Prepared research and analysis evaluating the reasonableness of the Grid Plan through comparison to how other electric utilities have responded to the changing energy landscape.
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			

Sponsor	Date	Docket No.	Subject
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Kentucky Public Service Commission			
Bluegrass Water Utility (Central States Water Company)	02/23	Case No. 2022-00432	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
Maine Public Utilities Commission			
Maine Water Company	03/21	Docket No. 2021-00053	Sponsored testimony supporting a proposed rate smoothing mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
Berkshire Gas Company, Eversource Energy, Liberty Utilities, National Grid, and Unitil	03/22	Docket No. DPU 20-80	Sponsored report that summarizes research, findings, and recommendations for regulatory mechanisms, methodologies, and policies that support Massachusetts's achievement of its net zero climate goal by 2050. The regulatory designs were informed by the results of quantitative and qualitative analysis of decarbonization pathways to achieve the Commonwealth's climate goals.
Liberty Utilities (New England Gas Company)	08/20	Docket No. DPU 20-92	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2020/2021 through 2024/2025.
Eversource Energy, National Grid, and Unitil	02/20	Docket No. DPU 19-55	Sponsored report that summarizes research and evaluation of funding approaches for infrastructure modifications that interconnect Distributed Generation (DG) projects.
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.

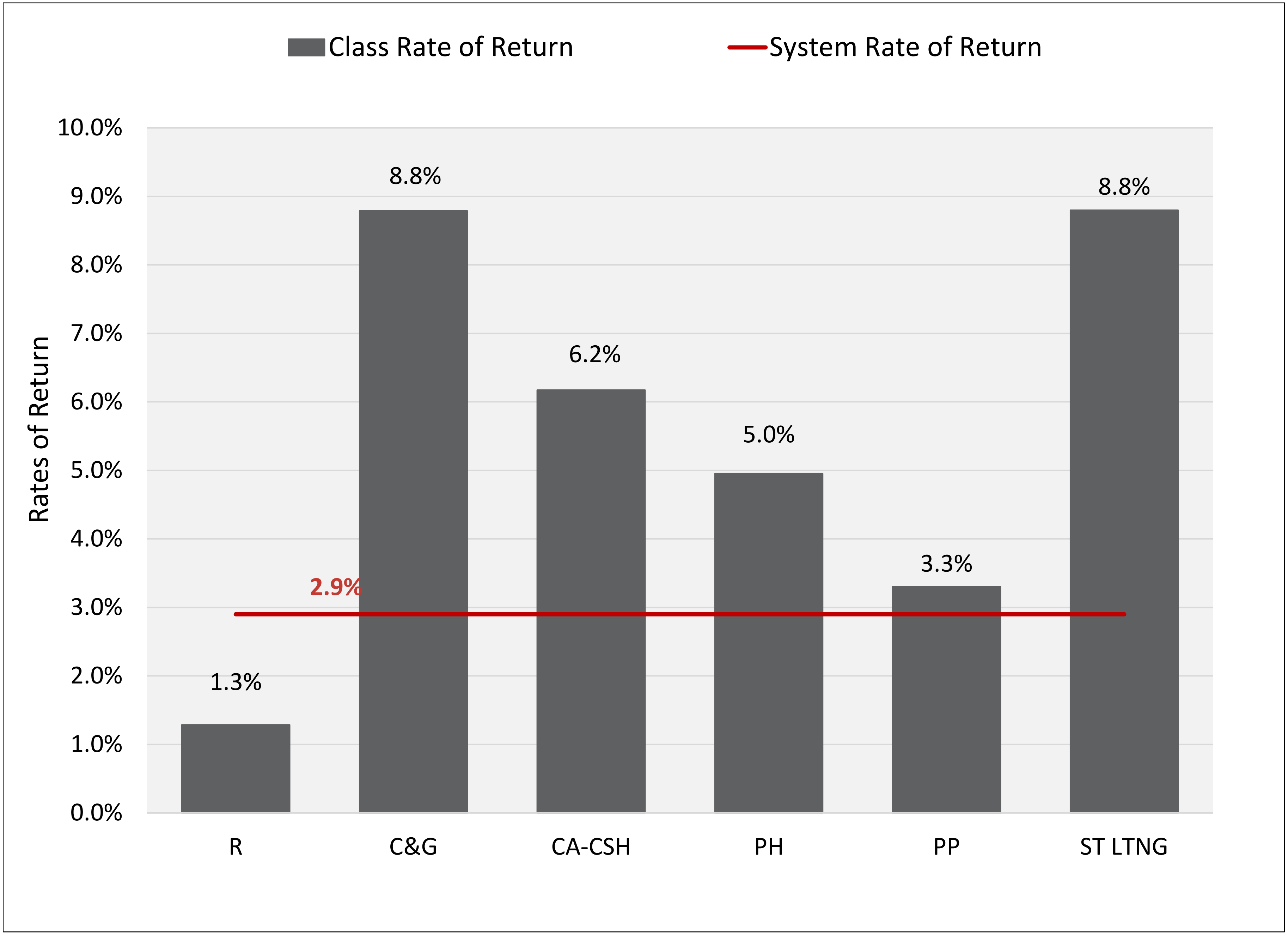
Sponsor	Date	Docket No.	Subject
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Minnesota Public Utilities Commission			
Northern States Power Company (XcelEnergy)	10/21	Docket No. E002/GR-21-630	Sponsored testimony supporting a Return on Equity (ROE)adjustment mechanism that would allow the Company to symmetrically adjust its ROE to reflect significant changesin financial market conditions.
Missouri Public Service Commission			
Confluence Rivers Utility Operating Company	12/22	Case No. WR-2023-0006/ SR-2023-0007	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
The Empire District Gas Company	08/21	Docket No. GR-2021-0320	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
The Empire District Electric Company	05/21	Docket No. ER-2021-0312	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Spire Missouri, Inc.	12/20	Docket No. GR-2021-0108	Sponsored testimony supporting class cost of service, rate design, and lead-lag study proposals for a general rate case proceeding. The testimony also included support for a proposed revenue adjustment mechanism.
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization

Sponsor	Date	Docket No.	Subject
			mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Nevada Public Utilities Commission			
Southwest Gas Corporation	09/21	Docket No. 21-09001	Sponsored testimony supporting the class cost of service,rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Southwest Gas Corporation	02/20	Docket No. 20-02023	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
New Hampshire Public Utilities Commission			
Unitil (Northern Utilities, Inc.)	8/21	Docket No. DG 21-104	Sponsored testimony supporting a revenue decoupling mechanism.
Unitil Energy Systems, Inc.	4/21	Docket No. DE 21-030	Sponsored testimony supporting a revenue decoupling mechanism.
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
New Jersey Board of Public Utilities			
South Jersey Gas Company	04/22	Docket No. GR22040253	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	12/21	Docket No. GR21121254	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
South Jersey Gas Company	03/20	Docket No. GR20030243	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Corporation Commission of Oklahoma			
The Empire District Electric Company	02/21	Cause No. PUD 202100163	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The proposed rate design included a three-year phase-in of the proposed rate increase.
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.

Sponsor	Date	Docket No.	Subject
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
Texas Gas Service Company – West Texas, North Texas, and Borger/ Skellytown Service Areas	06/22	Case No. 00009896	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Central Texas and Gulf Coast Service Areas	12/19	GUD No. 10928	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Beaumont/ East Texas Division	11/19	GUD No. 10920	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Borger/ Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
Virginia State Corporation Commission			
Rappahannock Electric Cooperative	10/22	Case No. PUR-2022-00160	Sponsored report and studies related to revenue requirements, class cost of service, rate design, and bill impact analysis for a streamlined application to increase base rates.

Sponsor	Date	Docket No.	Subject
American Electric Power - Appalachian Power Company	3/20	Case No. PUR-2020-00015	Sponsored testimony supporting the Lead/Lag study for the 2020 triennial review of base rates, terms, and conditions.
Nova Scotia Utility and Review Board			
Nova Scotia Power	01/22	Matter No. M10431	Sponsored evidence supporting the cash working capital requirement and lead/Lag study for a general rate case proceeding.
Ontario Energy Board			
Ontario Energy Association	01/21	Docket No. EB-2020-0133	Sponsored evidence regarding policies and ratemaking treatment related to COVID-19 costs in U.S. and Canadian regulatory jurisdictions. The evidence was used to support Ontario Energy Association's response to Staff's proposals


Class Rate of Return
System Rate of Return
Rates of Return
10.0%
9.0%
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
8.8%
6.2%
5.0%
3.3%
8.8%
2.9%
1.3%
R
C&G
CA-CSH
PH
PP
ST LTNG

The Potomac Edison Company (Maryland) COSS Summary Proposed		Total Company		Residential Service R		Small C & I Schedule C&G		Small C & I Schedule CA-CSH		Medium Power Schedule PH		Large Power Schedule PP		Street and Area Lighting ST LTNG
Current Delivery Service Rates														
Rate base	$	718,525,219	$	513,322,007	$	87,962,622	$	1,872,194	$	87,055,863	$	7,486,116	$	20,826,416
Net operating income	$	20,838,731	$	6,603,275	$	7,729,383	$	115,570	$	4,310,623	$	247,333	$	1,832,547
Rate of return		2.90%		1.29%		8.79%		6.17%		4.95%		3.30%		8.80%
Relative rate of return		100%		44%		303%		213%		171%		114%		303%
Revenues	$	138,842,885	$	86,532,923	$	25,361,406	$	447,672	$	19,989,257	$	1,427,087	$	5,084,540
Test Period Usage (MWh)		6,819,525,904		3,354,870,600		905,734,700		23,300,136		1,802,643,017		709,586,291		23,391,160
Revenue per MWh	$	0.02	$	0.03	$	0.03	$	0.02	$	0.01	$	0.00	$	0.22
Revenues at Equalized Rates of Return														
Rate of return		7.54%		7.54%		7.54%		7.54%		7.54%		7.54%		7.54%
Return requirement	$	54,188,230	$	38,712,644	$	6,633,781	$	141,193	$	6,565,397	$	564,572	$	1,570,643
Revenue required	$	186,335,533	$	132,259,515	$	23,801,172	$	484,162	$	23,200,255	$	1,878,864	$	4,711,565
Revenue deficiency	$	47,492,648	$	45,726,592	$	(1,560,234)	$	36,490	$	3,210,998	$	451,777	$	(372,975)
Percent increase required		34.2%		52.8%		-6.2%		8.2%		16.1%		31.7%		-7.3%
Test Period Usage (MWh)		6,819,525,904		3,354,870,600		905,734,700		23,300,136		1,802,643,017		709,586,291		23,391,160
Revenue Required per MWh	$	0.03	$	0.04	$	0.03	$	0.02	$	0.01	$	0.00	$	0.20
Revenue Deficiency per MWh	$	0.01	$	0.01	$	(0.00)	$	0.00	$	0.00	$	0.00	$	(0.02)

Rate Class	Proposed Class ROR	Overall ROR	Alternative Class ROR
R	1.29%	2.90%	2.25%
C&G	8.79%	2.90%	7.65%
CA-CSH	6.17%	2.90%	2.99%
PH	4.95%	2.90%	0.87%
PP	3.30%	2.90%	3.29%
ST LTNG	8.80%	2.90%	8.22%

The Potomac Edison Company (Maryland) COSS Summary		Total Company		Residential Service R		Schedule C&G		Schedule CA-CSH		Schedule PH		Schedule PP		Area Lighting ST LTNG
Current Rate of Return		2.90%		1.29%		8.79%		6.17%		4.95%		3.30%		8.80%
Proposed Rate of Return		7.54%		7.54%		7.54%		7.54%		7.54%		7.54%		7.54%
EROR Revenues	$	186,335,533	$	132,259,515	$	23,801,172	$	484,162	$	23,200,255	$	1,878,864	$	4,711,565
Current Revenues		138,842,885		86,532,923		25,361,406		447,672		19,989,257		1,427,087		5,084,540
Difference	$	47,492,648	$	45,726,592	$	(1,560,234)	$	36,490	$	3,210,998	$	451,777	$	(372,975)
% Difference		34.21%		52.84%		-6.15%		8.15%		16.06%		31.66%		-7.34%
Derivation of Delivery Revenues														
Current Total Revenues	$	138,842,885		86,532,923		25,361,406		447,672		19,989,257		1,427,087		5,084,540
Less: Franchise Fees	$	4,256,657		2,108,602		564,626		14,498		1,117,658		436,690		14,582
Less: Montgomery County	$	9,797,215		4,686,975		1,784,838		38,374		3,146,485		-		140,543
Less: Other Revenues	$	4,594,731		3,098,877		690,144		12,129		626,533		52,129		114,919
Current Delivery Revenues	$	120,194,282	$	76,638,469	$	22,321,797	$	382,670	$	15,098,581	$	938,268	$	4,814,496
Total Revenues at EROR	$	186,335,533		132,259,515		23,801,172		484,162		23,200,255		1,878,864		4,711,565
Less: Franchise Fees	$	4,256,657		2,108,602		564,626		14,498		1,117,658		436,690		14,582
Less: Montgomery County	$	9,797,215		4,686,975		1,784,838		38,374		3,146,485		-		140,543
Less: Other Revenues	$	4,594,731		3,098,877		690,144		12,129		626,533		52,129		114,919
Delivery Revenues at EROR	$	167,686,930	$	122,365,061	$	20,761,563	$	419,160	$	18,309,580	$	1,390,045	$	4,441,521
Metrics														
Delivery Revenues at EROR		167,686,930		122,365,061		20,761,563		419,160		18,309,580		1,390,045		4,441,521
Test Period Usage (MWh)		6,819,525,904		3,354,870,600		905,734,700		23,300,136		1,802,643,017		709,586,291		23,391,160
Test Period Customers		284,640		250,592		31,222		325		1,682		10		809

The Potomac Edison Company (Maryland) Income Statement Current Rates	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
Going-Level Income Statement							
Operating Revenues	**$ 138,842,885**	**$ 86,532,923**	**$ 25,361,406**	**$ 447,672**	**$ 19,989,257**	**$ 1,427,087**	**$ 5,084,540**
Operating Expenses							
O&M Expenses	$ 56,655,385	$ 42,125,174	$ 7,139,442	$ 135,661	$ 5,454,835	$ 602,358	$ 1,197,916
Depreciation & Amortization	33,822,024	24,109,232	4,170,259	86,586	4,204,947	337,175	913,825
Regulatory Debits and Credits	1,288,352	991,766	143,497	2,089	75,729	60,707	14,563
Taxes Other than Income	30,607,318	18,969,699	4,747,773	95,888	5,794,482	213,560	785,916
Total Operating Expenses	$ 122,373,079	$ 86,195,871	$ 16,200,971	$ 320,224	$ 15,529,994	$ 1,213,800	$ 2,912,220
Income Before Tax	$ 16,469,806	$ 337,053	$ 9,160,435	$ 127,448	$ 4,459,263	$ 213,287	$ 2,172,321
Income Adjustments							
Adjustment to Income - MD	$ 8,141,525	5,816,391	996,694	21,214	986,420	84,824	235,982
Interest Expense	13,420,137	9,587,488	1,642,907	34,968	1,625,972	139,821	388,982
Schedule M Adjustments	31,522,110	22,519,728	3,858,970	82,134	3,819,190	328,420	913,667
Total Income Adjustments	$ 53,083,772	$ 37,923,607	$ 6,498,572	$ 138,315	$ 6,431,582	$ 553,065	$ 1,538,630
Adjusted Taxable Income	$ (36,613,966)	$ (37,586,555)	$ 2,661,863	$ (10,868)	$ (1,972,319)	$ (339,778)	$ 633,690
State Income Tax	$ (3,020,652)	$ (3,100,891)	$ 219,604	$ (897)	$ (162,716)	$ (28,032)	$ 52,279
Federal Income Tax	(7,054,596)	(7,241,989)	512,874	(2,094)	(380,017)	(65,467)	122,096
Deferred Taxes	8,298,486	5,928,526	1,015,910	21,623	1,005,437	86,460	240,531
Total Income Taxes	$ (1,776,762)	$ (4,414,354)	$ 1,748,388	$ 18,632	$ 462,704	$ (7,039)	$ 414,907
AFUDC	2,609,343	1,864,142	319,438	6,799	316,146	27,186	75,632
Interest on Customer Deposits	(17,180)	(12,273)	(2,103)	(45)	(2,081)	(179)	(498)
Total Operating Income	**$ 20,838,731**	**$ 6,603,275**	**$ 7,729,383**	**$ 115,570**	**$ 4,310,623**	**$ 247,333**	**$ 1,832,547**
Rate Base	**$ 718,525,219**	**$ 513,322,007**	**$ 87,962,622**	**$ 1,872,194**	**$ 87,055,863**	**$ 7,486,116**	**$ 20,826,416**
ROR @ Current Rates	2.90%	1.29%	8.79%	6.17%	4.95%	3.30%	8.80%
Rate Base %	100.00%	71.44%	12.24%	0.26%	12.12%	1.04%	2.90%
Pro-Forma Income Tax Increase Calculation							
Rate Base	718,525,219	513,322,007	87,962,622	1,872,194	87,055,863	7,486,116	20,826,416
Required ROR	7.54%	7.54%	7.54%	7.54%	7.54%	7.54%	7.54%
Required Income	54,188,230	38,712,644	6,633,781	141,193	6,565,397	564,572	1,570,643
Increase in Earnings Requested	33,349,500	32,109,369	(1,095,602)	25,624	2,254,774	317,239	(261,904)
Increase in Revenues Requested	47,492,648	45,726,592	(1,560,234)	36,490	3,210,998	451,777	(372,975)
Pro-Forma Uncollectible Expense	400,682	385,782	(13,163)	308	27,090	3,812	(3,147)
Pro-Forma Regulatory Assessment	131,697	126,800	(4,327)	101	8,904	1,253	(1,034)
Pro-Forma Maryland Gross Receipt Tax	949,853	914,532	(31,205)	730	64,220	9,036	(7,460)
State Taxable Income	46,010,416	44,299,478	(1,511,540)	35,351	3,110,784	437,677	(361,335)
State Income Tax Increase	**3,795,859**	**3,654,707**	**(124,702)**	**2,916**	**256,640**	**36,108**	**(29,810)**
Federal Taxable Income	42,214,557	40,644,771	(1,386,838)	32,435	2,854,144	401,569	(331,525)
Federal Income Tax Increase	**8,865,057**	**8,535,402**	**(291,236)**	**6,811**	**599,370**	**84,329**	**(69,620)**
Revenue Requirement Calculation							
Required Income	54,188,230	38,712,644	6,633,781	141,193	6,565,397	564,572	1,570,643
Add: Expenses							
Current Expenses	122,373,079	86,195,871	16,200,971	320,224	15,529,994	1,213,800	2,912,220
Proforma Expense Increase	1,482,232	1,427,114	(48,694)	1,139	100,214	14,100	(11,640)
Add: Taxes							
Current Taxes	(1,776,762)	(4,414,354)	1,748,388	18,632	462,704	(7,039)	414,907
Proforma Tax Increase	12,660,916	12,190,109	(415,938)	9,728	856,010	120,438	(99,430)
Less: Other Revenues	(2,592,163)	(1,851,869)	(317,335)	(6,754)	(314,064)	(27,007)	(75,134)
Revenue Requirement	**186,335,533**	**132,259,515**	**23,801,172**	**484,162**	**23,200,255**	**1,878,864**	**4,711,565**

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
UTILITY PLANT									
Distribution Plant									
(360) Land and Land Rights		22,832,423							
- Demand		17,881,293	11,136,534	2,367,055	67,605	4,112,972	97,798	99,329	
- Customer		4,951,130	4,360,759	542,746	5,639	27,907	1	14,078	
- Commodity		-	-	-	-	-	-	-	
Total		22,832,423	15,497,293	2,909,801	73,244	4,140,880	97,799	113,407	
(361) Structures and Improvements		11,490,605							
- Demand		11,490,605	7,051,472	1,542,653	45,423	2,757,913	24,799	68,345	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		11,490,605	7,051,472	1,542,653	45,423	2,757,913	24,799	68,345	
(362) Station Equipment		190,214,295							
- Demand		190,214,295	116,743,761	25,505,973	750,704	45,638,656	448,509	1,126,692	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		190,214,295	116,743,761	25,505,973	750,704	45,638,656	448,509	1,126,692	
(362) Station Equipment - Capacitors		1,528,215							
- Demand		1,528,215	962,922	151,304	3,909	339,726	69,416	938	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,528,215	962,922	151,304	3,909	339,726	69,416	938	
(364) Poles, Towers & Fixtures		134,210,133							
- Demand		104,424,307	66,800,055	12,953,535	344,253	22,091,524	1,804,418	430,522	
- Customer		29,785,825	26,234,070	3,265,163	33,924	167,971	5	84,693	
- Commodity		-	-	-	-	-	-	-	
Total		134,210,133	93,034,124	16,218,698	378,177	22,259,495	1,804,423	515,214	
(365) Overhead Conductors & Devices		245,148,184							
- Demand		150,243,366	95,316,912	16,694,226	438,564	32,671,817	4,774,049	347,800	
- Customer		94,904,817	83,588,494	10,403,516	108,086	534,856	11	269,853	
- Commodity		-	-	-	-	-	-	-	
Total		245,148,184	178,905,406	27,097,742	546,650	33,206,673	4,774,060	617,653	
(366) Underground Conduit		70,132,572							
- Demand		70,132,572	44,988,805	8,987,118	239,504	14,697,227	890,704	329,214	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		70,132,572	44,988,805	8,987,118	239,504	14,697,227	890,704	329,214	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(367) Underground Conductors & Device		319,482,180							
- Demand		142,323,156	90,389,394	15,923,854	418,025	30,841,943	4,405,834	344,106	
- Customer		177,159,024	156,035,964	19,420,051	201,753	997,507	9	503,740	
- Commodity		-	-	-	-	-	-	-	
Total		319,482,180	246,425,358	35,343,905	619,779	31,839,450	4,405,843	847,846	
(368) Line Transformers		207,846,214							
- Demand		51,392,381	33,272,620	7,174,563	191,934	10,430,032	518	322,715	
- Customer		156,453,834	137,800,143	17,150,242	178,167	880,414	0	444,868	
- Commodity		-	-	-	-	-	-	-	
Total		207,846,214	171,072,763	24,324,804	370,101	11,310,445	518	767,582	
(368) Line Transformers - Capacitors		1,518,797							
- Demand		1,518,797	928,164	146,877	3,768	327,464	111,621	905	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,518,797	928,164	146,877	3,768	327,464	111,621	905	
(369) Services		73,051,113							
- Demand		-	-	-	-	-	-	-	
- Customer		73,051,113	64,524,857	8,030,589	83,427	412,241	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		73,051,113	64,524,857	8,030,589	83,427	412,241	-	-	
(370, 371) Meters and Installation		58,934,191							
- Demand		-	-	-	-	-	-	-	
- Customer		58,934,191	35,003,730	16,591,288	366,058	5,986,423	986,692	-	
- Commodity		-	-	-	-	-	-	-	
Total		58,934,191	35,003,730	16,591,288	366,058	5,986,423	986,692	-	
Street Lighting & Signal Systems		33,964,292							
- Demand		-	-	-	-	-	-	-	
- Customer		33,964,292	-	-	-	-	-	33,964,292	
- Commodity		-	-	-	-	-	-	-	
Total		33,964,292	-	-	-	-	-	33,964,292	
Total Distribution Plant		1,370,353,215							
- Demand		741,148,989	467,590,638	91,447,157	2,503,690	163,909,274	12,627,665	3,070,565	
- Customer		629,204,227	507,548,017	75,403,594	977,055	9,007,319	986,718	35,281,524	
- Commodity		-	-	-	-	-	-	-	
Total		1,370,353,215	975,138,655	166,850,751	3,480,745	172,916,593	13,614,383	38,352,088	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
General and Intangible Plant									
General Plant		58,345,763							
- Demand		23,863,649	14,974,261	2,870,550	79,075	5,368,742	481,812	89,210	
- Customer		34,482,114	26,544,032	5,184,145	83,194	924,191	127,414	1,619,138	
- Commodity		-	-	-	-	-	-	-	
Total		58,345,763	41,518,293	8,054,695	162,269	6,292,933	609,225	1,708,347	
Intangible Plant		36,519,232							
- Demand		14,936,511	9,372,549	1,796,708	49,494	3,360,353	301,571	55,837	
- Customer		21,582,721	16,614,191	3,244,811	52,072	578,461	79,750	1,013,436	
- Commodity		-	-	-	-	-	-	-	
Total		36,519,232	25,986,740	5,041,519	101,566	3,938,814	381,321	1,069,273	
Total General and Intangible Plant		94,864,996							
- Demand		38,800,160	24,346,810	4,667,257	128,568	8,729,095	783,383	145,047	
- Customer		56,064,835	43,158,223	8,428,956	135,266	1,502,652	207,164	2,632,573	
- Commodity		-	-	-	-	-	-	-	
Total		94,864,996	67,505,034	13,096,214	263,834	10,231,747	990,546	2,777,620	
Additions to Utility Plant									
COVID-19 Regulatory Asset Adj excl. Res Adj		9,651,602							
- Demand		5,220,023	4,332,967	392,790	6,934	308,273	157,236	21,822	
- Customer		4,431,579	3,678,506	333,462	5,887	261,711	133,487	18,526	
- Commodity		-	-	-	-	-	-	-	
Total		9,651,602	8,011,472	726,253	12,821	569,984	290,722	40,349	
COVID-19 Residential Adjustment		(2,391,373)							
- Demand		(1,293,363)	(1,293,363)	-	-	-	-	-	
- Customer		(1,098,010)	(1,098,010)	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		(2,391,373)	(2,391,373)	-	-	-	-	-	
MD Electric Vehicle Program Reg Asset excl. Res Direct		670,401							
- Demand		456,359	-	158,433	4,311	271,063	16,810	5,742	
- Customer		214,042	-	152,242	1,818	14,094	1,206	44,682	
- Commodity		-	-	-	-	-	-	-	
Total		670,401	-	310,675	6,130	285,156	18,016	50,424	
MD EV Reg Asset - Residential Direct		855,889							
- Demand		462,903	462,903	-	-	-	-	-	
- Customer		392,985	392,985	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		855,889	855,889	-	-	-	-	-	
Total Additional to Utility Plant		8,786,519							
- Demand		4,845,923	3,502,507	551,224	11,246	579,336	174,046	27,564	
- Customer		3,940,596	2,973,481	485,704	7,705	275,805	134,693	63,209	
- Commodity		-	-	-	-	-	-	-	
Total		8,786,519	6,475,988	1,036,928	18,951	855,141	308,739	90,773	
Total Utility Plant		1,474,004,730							
- Demand		784,795,072	495,439,955	96,665,638	2,643,504	173,217,705	13,585,094	3,243,176	
- Customer		689,209,658	553,679,721	84,318,255	1,120,026	10,785,776	1,328,574	37,977,306	
- Commodity		-	-	-	-	-	-	-	
Total		**1,474,004,730**	**1,049,119,676**	**180,983,892**	**3,763,530**	**184,003,481**	**14,913,668**	**41,220,482**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
Distribution Plant A/D		(524,692,906)							
- Demand		(283,777,651)	(179,035,221)	(35,014,093)	(958,635)	(62,759,026)	(4,834,992)	(1,175,685)	
- Customer		(240,915,255)	(194,334,454)	(28,871,192)	(374,103)	(3,448,802)	(377,803)	(13,508,900)	
- Commodity		-	-	-	-	-	-	-	
Total		(524,692,906)	(373,369,675)	(63,885,285)	(1,332,738)	(66,207,828)	(5,212,795)	(14,684,585)	
General Plant A/D		(27,506,237)							
- Demand		(11,250,161)	(7,059,392)	(1,353,278)	(37,279)	(2,531,013)	(227,143)	(42,057)	
- Customer		(16,256,077)	(12,513,787)	(2,443,988)	(39,221)	(435,696)	(60,067)	(763,318)	
- Commodity		-	-	-	-	-	-	-	
Total		(27,506,237)	(19,573,178)	(3,797,265)	(76,499)	(2,966,709)	(287,210)	(805,375)	
Intangible Plant A/D		(24,687,910)							
- Demand		(12,882,646)	(8,120,915)	(1,583,094)	(43,386)	(2,857,247)	(225,480)	(52,525)	
- Customer		(11,805,264)	(9,918,552)	(1,469,911)	(18,944)	(157,878)	(15,954)	(224,025)	
- Commodity		-	-	-	-	-	-	-	
Total		(24,687,910)	(18,039,467)	(3,053,005)	(62,330)	(3,015,125)	(241,434)	(276,549)	
COVID Reg Asset A/D		(726,023)							
- Demand		(392,666)	(303,960)	(39,279)	(693)	(30,827)	(15,724)	(2,182)	
- Customer		(333,357)	(258,050)	(33,346)	(589)	(26,171)	(13,349)	(1,853)	
- Commodity		-	-	-	-	-	-	-	
Total		(726,023)	(562,010)	(72,625)	(1,282)	(56,998)	(29,072)	(4,035)	
EV Reg Asset A/D		(152,629)							
- Demand		(91,926)	(46,290)	(15,843)	(431)	(27,106)	(1,681)	(574)	
- Customer		(60,703)	(39,299)	(15,224)	(182)	(1,409)	(121)	(4,468)	
- Commodity		-	-	-	-	-	-	-	
Total		(152,629)	(85,589)	(31,067)	(613)	(28,516)	(1,802)	(5,042)	
CWIP A/D		(162,583)							
- Demand		(87,839)	(55,466)	(10,831)	(296)	(19,373)	(1,508)	(365)	
- Customer		(74,744)	(60,722)	(9,033)	(117)	(1,085)	(129)	(3,658)	
- Commodity		-	-	-	-	-	-	-	
Total		(162,583)	(116,188)	(19,864)	(413)	(20,458)	(1,637)	(4,022)	
Total Accumulated Depreciation		(577,928,288)							
- Demand		(308,482,889)	(194,621,244)	(38,016,418)	(1,040,720)	(68,224,593)	(5,306,527)	(1,273,387)	
- Customer		(269,445,399)	(217,124,864)	(32,842,694)	(433,156)	(4,071,041)	(467,423)	(14,506,222)	
- Commodity		-	-	-	-	-	-	-	
Total Accumulated Depreciation		**(577,928,288)**	**(411,746,107)**	**(70,859,112)**	**(1,473,876)**	**(72,295,634)**	**(5,773,950)**	**(15,779,609)**	
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Construction Work in Progress		50,574,771							
- Demand		26,927,207	16,999,106	3,316,707	90,702	5,943,296	466,120	111,277	
- Customer		23,647,564	18,997,378	2,893,055	38,429	370,072	45,585	1,303,044	
- Commodity		-	-	-	-	-	-	-	
Total		50,574,771	35,996,484	6,209,762	129,131	6,313,368	511,705	1,414,321	
Plant Held for Future Use		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Prepayments		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Working Capital		16,435,549							
- Demand		8,750,676	5,524,289	1,077,848	29,476	1,931,424	151,477	36,162	
- Customer		7,684,873	6,173,678	940,171	12,489	120,264	14,814	423,457	
- Commodity		-	-	-	-	-	-	-	
Total		16,435,549	11,697,967	2,018,019	41,964	2,051,688	166,291	459,619	
ADIT		(225,475,241)							
- Demand		(120,048,365)	(75,786,353)	(14,786,729)	(404,371)	(26,496,729)	(2,078,082)	(496,101)	
- Customer		(105,426,876)	(84,695,161)	(12,897,977)	(171,328)	(1,649,876)	(203,229)	(5,809,304)	
- Commodity		-	-	-	-	-	-	-	
Total		(225,475,241)	(160,481,515)	(27,684,705)	(575,699)	(28,146,605)	(2,281,311)	(6,305,406)	
Customer Advances		(5,061,698)							
- Demand		(2,737,595)	(1,727,148)	(337,780)	(9,248)	(605,435)	(46,643)	(11,342)	
- Customer		(2,324,103)	(1,874,739)	(278,520)	(3,609)	(33,270)	(3,645)	(130,320)	
- Commodity		-	-	-	-	-	-	-	
Total		(5,061,698)	(3,601,887)	(616,300)	(12,857)	(638,705)	(50,288)	(141,662)	
Customer Deposits		(14,024,604)							
- Demand		(7,467,032)	(4,079,756)	(1,112,198)	-	(2,253,073)	-	(22,005)	
- Customer		(6,557,572)	(3,582,855)	(976,736)	-	(1,978,657)	-	(19,325)	
- Commodity		-	-	-	-	-	-	-	
Total		(14,024,604)	(7,662,611)	(2,088,934)	-	(4,231,730)	-	(41,330)	
Deferred Investment Tax Credit		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Total Other Rate Base Items		(177,551,223)							
- Demand		(94,575,108)	(59,069,862)	(11,842,151)	(293,442)	(21,480,517)	(1,507,127)	(382,009)	
- Customer		(82,976,114)	(64,981,700)	(10,320,006)	(124,019)	(3,171,467)	(146,475)	(4,232,448)	
- Commodity		-	-	-	-	-	-	-	
Total		(177,551,223)	(124,051,562)	(22,162,158)	(417,460)	(24,651,984)	(1,653,602)	(4,614,456)	
Total Rate Base		**718,525,219**							
- Demand		**381,737,074**	**241,748,849**	**46,807,068**	**1,309,343**	**83,512,595**	**6,771,440**	**1,587,780**	
- Customer		**336,788,145**	**271,573,158**	**41,155,554**	**562,851**	**3,543,268**	**714,677**	**19,238,636**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**718,525,219**	**513,322,007**	**87,962,622**	**1,872,194**	**87,055,863**	**7,486,116**	**20,826,416**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
OPERATIONS & MAINTENANCE EXPENSES									
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering		68,716							
- Demand		27,202	17,245	3,158	84	5,928	704	83	
- Customer		41,514	30,337	7,080	126	1,750	266	1,954	
- Commodity		-	-	-	-	-	-	-	
Total		68,716	47,582	10,238	210	7,678	971	2,037	
(581) Load Dispatching		116,085							
- Demand		116,085	71,237	15,588	459	27,864	247	691	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		116,085	71,237	15,588	459	27,864	247	691	
(582) Station Expenses		16,885							
- Demand		16,885	10,362	2,267	67	4,053	36	101	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		16,885	10,362	2,267	67	4,053	36	101	
(583) Overhead line expenses		1,298,766							
- Demand		657,122	416,889	73,016	1,918	142,897	20,880	1,521	
- Customer		641,644	565,707	70,408	731	3,618	0	1,180	
- Commodity		-	-	-	-	-	-	-	
Total		1,298,766	982,596	143,423	2,650	146,515	20,880	2,701	
(584) Underground line expenses		1,434,107							
- Demand		741,566	472,531	86,950	2,295	158,952	18,487	2,350	
- Customer		692,541	610,155	75,939	789	3,900	0	1,758	
- Commodity		-	-	-	-	-	-	-	
Total		1,434,107	1,082,685	162,889	3,084	162,852	18,487	4,108	
(585) Street lighting and signal system expenses		107,100							
- Demand		-	-	-	-	-	-	-	
- Customer		107,100	-	-	-	-	-	107,100	
- Commodity		-	-	-	-	-	-	-	
Total		107,100	-	-	-	-	-	107,100	
(586) Meter expenses		896,233							
- Demand		-	-	-	-	-	-	-	
- Customer		896,233	532,314	252,310	5,567	91,038	15,005	-	
- Commodity		-	-	-	-	-	-	-	
Total		896,233	532,314	252,310	5,567	91,038	15,005	-	
(588) Miscellaneous distribution expenses		4,440,902							
- Demand		1,757,982	1,114,500	204,097	5,439	383,085	45,509	5,352	
- Customer		2,682,919	1,960,582	457,563	8,134	113,119	17,222	126,298	
- Commodity		-	-	-	-	-	-	-	
Total		4,440,902	3,075,082	661,661	13,574	496,203	62,731	131,650	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(589) Rents		1,069,104							
- Demand		423,217	268,305	49,134	1,309	92,224	10,956	1,288	
- Customer		645,887	471,991	110,154	1,958	27,232	4,146	30,405	
- Commodity		-	-	-	-	-	-	-	
Total		1,069,104	740,296	159,288	3,268	119,456	15,102	31,694	
Total Dist. Operations Expenses		9,447,898							
- Demand		3,740,060	2,371,069	434,211	11,572	815,002	96,819	11,386	
- Customer		5,707,839	4,171,086	973,454	17,306	240,657	36,640	268,697	
- Commodity		-	-	-	-	-	-	-	
Total		9,447,898	6,542,155	1,407,665	28,878	1,055,660	133,459	280,082	
Maintenance Expense									
(590) Maintenance Supervision and Engineering		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
(591) Maintenance of Structures		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
(592) Maintenance of Station Equipment		2,539,262							
- Demand		2,539,262	1,558,244	340,973	10,041	609,494	5,397	15,114	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		2,539,262	1,558,244	340,973	10,041	609,494	5,397	15,114	
(593) Maintenance of Overhead Lines		19,221,152							
- Demand		9,725,106	6,169,770	1,080,601	28,388	2,114,815	309,019	22,513	
- Customer		9,496,047	8,372,208	1,042,003	10,825	53,542	1	17,467	
- Commodity		-	-	-	-	-	-	-	
Total		19,221,152	14,541,978	2,122,604	39,213	2,168,357	309,020	39,980	
(594) Maintenance of underground lines		934,344							
- Demand		483,142	307,861	56,650	1,495	103,560	12,045	1,531	
- Customer		451,202	397,526	49,476	514	2,541	0	1,146	
- Commodity		-	-	-	-	-	-	-	
Total		934,344	705,387	106,125	2,009	106,101	12,045	2,677	
(595) Maintenance of line transformers		103,981							
- Demand		25,710	16,646	3,589	96	5,218	0	161	
- Customer		78,270	68,938	8,580	89	440	0	223	
- Commodity		-	-	-	-	-	-	-	
Total		103,981	85,584	12,169	185	5,658	0	384	
(596) Maintenance of street lighting and signal systems		465,742							
- Demand		-	-	-	-	-	-	-	
- Customer		465,742	-	-	-	-	-	465,742	
- Commodity		-	-	-	-	-	-	-	
Total		465,742	-	-	-	-	-	465,742	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(597) Maintenance of meters		914,278							
- Demand		-	-	-	-	-	-	-	
- Customer		914,278	543,032	257,390	5,679	92,871	15,307	-	
- Commodity		-	-	-	-	-	-	-	
Total		914,278	543,032	257,390	5,679	92,871	15,307	-	
(598) Maintenance of miscellaneous distribution plant		157,146							
- Demand		83,018	52,336	9,631	260	18,413	2,122	256	
- Customer		74,129	60,975	8,823	111	971	99	3,149	
- Commodity		-	-	-	-	-	-	-	
Total		157,146	113,311	18,453	371	19,384	2,221	3,405	
Total Dist. Maintenance Expenses		24,335,905							
- Demand		12,856,238	8,104,857	1,491,443	40,280	2,851,500	328,583	39,574	
- Customer		11,479,668	9,442,679	1,366,271	17,219	150,365	15,407	487,727	
- Commodity		-	-	-	-	-	-	-	
Total		24,335,905	17,547,537	2,857,714	57,498	3,001,865	343,990	527,301	
Total Distribution Expenses		33,783,804							
- Demand		16,596,297	10,475,926	1,925,655	51,852	3,666,502	425,402	50,960	
- Customer		17,187,507	13,613,765	2,339,724	34,524	391,022	52,047	756,423	
- Commodity		-	-	-	-	-	-	-	
Total		33,783,804	24,089,691	4,265,379	86,376	4,057,525	477,450	807,384	
Customer Accounts and Services									
Meter Reading & Billing		6,854,217							
- Demand		-	-	-	-	-	-	-	
- Customer		6,854,217	5,857,097	934,546	12,631	44,634	-	5,309	
- Commodity		-	-	-	-	-	-	-	
Total		6,854,217	5,857,097	934,546	12,631	44,634	-	5,309	
Other-Direct to Other		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Uncollectibles		1,132,614							
- Demand		-	-	-	-	-	-	-	
- Customer		1,132,614	1,131,744	330	6	259	275	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,132,614	1,131,744	330	6	259	275	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Misc. Cust Serv and Info Exp		2,381,813							
- Demand		-	-	-	-	-	-	-	
- Customer		2,381,813	2,178,507	182,913	2,013	6,213	-	12,167	
- Commodity		-	-	-	-	-	-	-	
Total		2,381,813	2,178,507	182,913	2,013	6,213	-	12,167	
Customer Rebates & Incentives		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Customer Assistance		233,396							
- Demand		-	-	-	-	-	-	-	
- Customer		233,396	233,396	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		233,396	233,396	-	-	-	-	-	
Sales Expense		1							
- Demand		-	-	-	-	-	-	-	
- Customer		1	1	0	0	0	-	0	
- Commodity		-	-	-	-	-	-	-	
Total		1	1	0	0	0	-	0	
All Other Cust Accts & Services		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Total Customer Accounts and Services		10,602,041							
- Demand		-	-	-	-	-	-	-	
- Customer		10,602,041	9,400,745	1,117,789	14,650	51,106	275	17,476	
- Commodity		-	-	-	-	-	-	-	
Total		10,602,041	9,400,745	1,117,789	14,650	51,106	275	17,476	
Administrative & General Expense									
Administrative and General Salaries		3,795,263							
- Demand		1,552,278	974,043	186,723	5,144	349,225	31,341	5,803	
- Customer		2,242,985	1,726,631	337,217	5,412	60,117	8,288	105,321	
- Commodity		-	-	-	-	-	-	-	
Total		3,795,263	2,700,673	523,940	10,555	409,341	39,629	111,124	
Outside Services		7,307,223							
- Demand		2,988,683	1,875,376	359,508	9,903	672,381	60,342	11,173	
- Customer		4,318,540	3,324,374	649,262	10,419	115,746	15,957	202,781	
- Commodity		-	-	-	-	-	-	-	
Total		7,307,223	5,199,751	1,008,770	20,323	788,127	76,299	213,953	
Employee Benefits (Acct. 926)		(2,265,273)							
- Demand		(926,506)	(581,375)	(111,449)	(3,070)	(208,441)	(18,706)	(3,464)	
- Customer		(1,338,768)	(1,030,572)	(201,274)	(3,230)	(35,882)	(4,947)	(62,863)	
- Commodity		-	-	-	-	-	-	-	
Total		(2,265,273)	(1,611,947)	(312,723)	(6,300)	(244,323)	(23,653)	(66,327)	
Regulatory Commission Expenses (Acct 928)		1,326,184							
- Demand		717,260	457,341	133,205	2,284	90,101	5,599	28,731	
- Customer		608,924	388,263	113,086	1,939	76,492	4,753	24,391	
- Commodity		-	-	-	-	-	-	-	
Total		1,326,184	845,604	246,291	4,222	166,593	10,353	53,122	
General Advertising Expense		45,306							
- Demand		16,940	10,693	1,966	53	3,742	434	52	
- Customer		28,365	23,491	3,529	50	451	53	790	
- Commodity		-	-	-	-	-	-	-	
Total		45,306	34,185	5,495	103	4,194	488	842	
All Other O&M		2,060,838							
- Demand		842,891	528,908	101,391	2,793	189,630	17,018	3,151	
- Customer		1,217,947	937,565	183,110	2,939	32,643	4,500	57,190	
- Commodity		-	-	-	-	-	-	-	
Total		2,060,838	1,466,473	284,501	5,732	222,274	21,519	60,341	
Total A&G Expense		12,269,540							
- Demand		5,191,547	3,264,985	671,344	17,106	1,096,638	96,028	45,445	
- Customer		7,077,994	5,369,753	1,084,930	17,528	249,567	28,606	327,610	
- Commodity		-	-	-	-	-	-	-	
Total		12,269,540	8,634,738	1,756,274	34,635	1,346,205	124,634	373,055	
Total O&M Expenses		56,655,385							
- Demand		21,787,844	13,740,911	2,596,998	68,958	4,763,140	521,430	96,406	
- Customer		34,867,542	28,384,262	4,542,443	66,703	691,695	80,928	1,101,510	
- Commodity		-	-	-	-	-	-	-	
Total		**56,655,385**	**42,125,174**	**7,139,442**	**135,661**	**5,454,835**	**602,358**	**1,197,916**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
DEPRECIATION EXPENSE									
Depreciation Expense									
Distribution Plant DeprExp		28,696,459							
- Demand		15,520,343	9,791,779	1,914,988	52,430	3,432,411	264,435	64,300	
- Customer		13,176,116	10,628,523	1,579,021	20,460	188,622	20,663	738,828	
- Commodity		-	-	-	-	-	-	-	
Total		28,696,459	20,420,302	3,494,008	72,890	3,621,033	285,098	803,128	
General Plant DeprExp		2,947,291							
- Demand		1,205,454	756,413	145,004	3,994	271,198	24,338	4,506	
- Customer		1,741,837	1,340,851	261,873	4,202	46,685	6,436	81,790	
- Commodity		-	-	-	-	-	-	-	
Total		2,947,291	2,097,265	406,877	8,197	317,883	30,775	86,296	
Intangible Plant DeprExp		2,178,273							
- Demand		1,136,667	716,528	139,680	3,828	252,102	19,895	4,634	
- Customer		1,041,607	875,138	129,694	1,671	13,930	1,408	19,766	
- Commodity		-	-	-	-	-	-	-	
Total		2,178,273	1,591,665	269,374	5,500	266,032	21,302	24,401	
Total Depreciation Expenses		33,822,024							
- Demand		17,862,463	11,264,720	2,199,672	60,252	3,955,711	308,668	73,441	
- Customer		15,959,561	12,844,512	1,970,588	26,334	249,236	28,507	840,383	
- Commodity		-	-	-	-	-	-	-	
Total		**33,822,024**	**24,109,232**	**4,170,259**	**86,586**	**4,204,947**	**337,175**	**913,825**	
Regulatory Debits and Credits									
MD EDIS		(393,539)							
- Demand		(393,539)	(250,019)	(54,188)	(1,501)	(85,104)	(303)	(2,425)	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		(393,539)	(250,019)	(54,188)	(1,501)	(85,104)	(303)	(2,425)	
MD Electric Vehicle Program		305,258							
- Demand		180,864	91,234	31,064	846	53,259	3,340	1,122	
- Customer		124,394	79,944	30,594	372	3,018	278	10,188	
- Commodity		-	-	-	-	-	-	-	
Total		305,258	171,178	61,657	1,218	56,277	3,618	11,310	
MD Conservation Voltage Reduction (CVR)		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Deferral of Rate Case Expenses		(75,413)							
- Demand		(40,193)	(25,352)	(4,954)	(136)	(8,896)	(690)	(166)	
- Customer		(35,219)	(28,061)	(4,269)	(57)	(545)	(63)	(2,226)	
- Commodity		-	-	-	-	-	-	-	
Total		(75,413)	(53,412)	(9,223)	(192)	(9,441)	(753)	(2,391)	
COVID-19		1,930,321							
- Demand		1,044,005	866,593	78,558	1,387	61,655	31,447	4,364	
- Customer		886,316	735,701	66,692	1,177	52,342	26,697	3,705	
- Commodity		-	-	-	-	-	-	-	
Total		1,930,321	1,602,295	145,251	2,564	113,997	58,145	8,070	
COVID-19 - Residential Adjustment		(478,275)							
- Demand		(258,673)	(258,673)	-	-	-	-	-	
- Customer		(219,602)	(219,602)	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		(478,275)	(478,275)	-	-	-	-	-	
Total Regulatory Debits and Credits		1,288,352							
- Demand		532,464	423,784	50,480	596	20,914	33,794	2,896	
- Customer		755,889	567,982	93,017	1,493	54,816	26,913	11,668	
- Commodity		-	-	-	-	-	-	-	
Total		1,288,352	991,766	143,497	2,089	75,729	60,707	14,563	
Taxes Other than Income									
Distribution Payroll Taxes		621,313							
- Demand		308,114	193,339	37,063	1,021	69,318	6,221	1,152	
- Customer		313,199	229,842	49,005	832	11,078	1,645	20,798	
- Commodity		-	-	-	-	-	-	-	
Total		621,313	423,181	86,068	1,853	80,396	7,866	21,950	
Customer Account Payroll Taxes		228,896							
- Demand		-	-	-	-	-	-	-	
- Customer		228,896	195,719	31,088	420	1,483	-	186	
- Commodity		-	-	-	-	-	-	-	
Total		228,896	195,719	31,088	420	1,483	-	186	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
A&G Payroll Taxes		12,736							
- Demand		5,209	3,269	627	17	1,172	105	19	
- Customer		7,527	5,794	1,132	18	202	28	353	
- Commodity		-	-	-	-	-	-	-	
Total		12,736	9,063	1,758	35	1,374	133	373	
Gross Receipt Taxes		6,955,508							
- Demand		3,703,278	2,301,554	680,565	12,015	534,127	37,929	137,089	
- Customer		3,252,231	2,021,233	597,674	10,551	469,072	33,309	120,392	
- Commodity		-	-	-	-	-	-	-	
Total		6,955,508	4,322,787	1,278,239	22,566	1,003,199	71,238	257,480	
Property Taxes		13,480,260							
- Demand		7,177,210	4,530,962	884,039	24,176	1,584,133	124,240	29,660	
- Customer		6,303,050	5,063,584	771,118	10,243	98,639	12,150	347,315	
- Commodity		-	-	-	-	-	-	-	
Total		13,480,260	9,594,546	1,655,157	34,419	1,682,773	136,390	376,975	
Sales & Use Tax		(202,486)							
- Demand		(107,808)	(67,002)	(19,812)	(350)	(15,549)	(1,104)	(3,991)	
- Customer		(94,677)	(58,841)	(17,399)	(307)	(13,655)	(970)	(3,505)	
- Commodity		-	-	-	-	-	-	-	
Total		(202,486)	(125,843)	(37,211)	(657)	(29,205)	(2,074)	(7,496)	
Montgomery County Fuel Energy		9,510,444							
- Demand		5,063,586	2,422,413	922,475	19,833	1,626,227	-	72,638	
- Customer		4,446,858	2,127,371	810,120	17,417	1,428,158	-	63,791	
- Commodity		-	-	-	-	-	-	-	
Total		9,510,444	4,549,784	1,732,595	37,251	3,054,385	-	136,430	
Other Taxes		646							
- Demand		344	218	42	1	75	6	1	
- Customer		302	244	37	1	3	1	17	
- Commodity		-	-	-	-	-	-	-	
Total		646	462	79	2	78	7	18	
Total Taxes Other than Income		30,607,318							
- Demand		16,149,933	9,384,754	2,504,998	56,713	3,799,503	167,397	236,569	
- Customer		14,457,385	9,584,945	2,242,775	39,175	1,994,979	46,163	549,347	
- Commodity		-	-	-	-	-	-	-	
Total Taxes Other than Income		30,607,318	18,969,699	4,747,773	95,888	5,794,482	213,560	785,916	
Total Operating Expenses		**122,373,079**							
- Demand		**56,332,704**	**34,814,169**	**7,352,148**	**186,519**	**12,539,268**	**1,031,289**	**409,311**	
- Customer		**66,040,375**	**51,381,702**	**8,848,823**	**133,705**	**2,990,726**	**182,511**	**2,502,908**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**122,373,079**	**86,195,871**	**16,200,971**	**320,224**	**15,529,994**	**1,213,800**	**2,912,220**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
UTILITY PLANT									
Distribution Plant									
(360) Land and Land Rights		1,580,034							DEM
- Demand	12CP-SUB	1,580,034	995,572	156,434	4,042	351,246	71,769	970	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		1,580,034	995,572	156,434	4,042	351,246	71,769	970	
(361) Structures and Improvements		8,742							DEM
- Demand	12CP-SUB	8,742	5,508	866	22	1,943	397	5	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		8,742	5,508	866	22	1,943	397	5	
(362) Station Equipment		1,021,961							DEM
- Demand	12CP-SUB	1,021,961	643,933	101,181	2,614	227,185	46,420	628	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		1,021,961	643,933	101,181	2,614	227,185	46,420	628	
(362) Station Equipment - Capacitors		1,528,215							DEM
- Demand	12CP-SUB	1,528,215	962,922	151,304	3,909	339,726	69,416	938	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		1,528,215	962,922	151,304	3,909	339,726	69,416	938	
(364) Poles, Towers & Fixtures		39,543,103							DEM
- Demand	12CP-SUB	39,543,103	24,915,934	3,915,037	101,153	8,790,542	1,796,154	24,283	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		39,543,103	24,915,934	3,915,037	101,153	8,790,542	1,796,154	24,283	
(365) Overhead Conductors & Devices		104,904,585							DEM
- Demand	12CP-SUB	104,904,585	66,099,913	10,386,270	268,352	23,320,581	4,765,048	64,421	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		104,904,585	66,099,913	10,386,270	268,352	23,320,581	4,765,048	64,421	
(366) Underground Conduit		19,489,104							DEM
- Demand	12CP-SUB	19,489,104	12,279,998	1,929,554	49,854	4,332,482	885,247	11,968	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		19,489,104	12,279,998	1,929,554	49,854	4,332,482	885,247	11,968	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(367) Underground Conductors & Device		96,882,582							DEM
- Demand	12CP-SUB	96,882,582	61,045,285	9,592,037	247,831	21,537,267	4,400,667	59,495	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		96,882,582	61,045,285	9,592,037	247,831	21,537,267	4,400,667	59,495	
(368) Line Transformers		-							DEM
- Demand	12CP-SUB	-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(368) Line Transformers - Capacitors		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(369) Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(370, 371) Meters and Installation		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Street Lighting & Signal Systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Distribution Plant		264,958,327							
- Demand		264,958,327	166,949,066	26,232,684	677,778	58,900,973	12,035,118	162,709	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		264,958,327	166,949,066	26,232,684	677,778	58,900,973	12,035,118	162,709	
General and Intangible Plant									
General Plant		10,191,837							LABOR-SUB
- Demand	LABOR-SUB-D	10,191,837	6,421,832	1,009,062	26,071	2,265,674	462,941	6,259	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		10,191,837	6,421,832	1,009,062	26,071	2,265,674	462,941	6,259	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant		6,379,179							LABOR-SUB
- Demand	LABOR-SUB-D	6,379,179	4,019,493	631,582	16,318	1,418,109	289,759	3,917	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		6,379,179	4,019,493	631,582	16,318	1,418,109	289,759	3,917	
Total General and Intangible Plant		16,571,017							
- Demand		16,571,017	10,441,324	1,640,644	42,390	3,683,783	752,700	10,176	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		16,571,017	10,441,324	1,640,644	42,390	3,683,783	752,700	10,176	
Additions to Utility Plant									
COVID-19 Regulatory Asset Adj excl. Res Adj		1,866,141							DISTPLT-SUB
- Demand	COVID	1,866,141	1,549,021	140,421	2,479	110,207	56,211	7,801	100%
- Customer	COVID	-	-	-	-	-	-	-	0%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		1,866,141	1,549,021	140,421	2,479	110,207	56,211	7,801	
COVID-19 Residential Adjustment		(462,373)							DISTPLT-SUB
- Demand	Res-Direct	(462,373)	(462,373)	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(462,373)	(462,373)	-	-	-	-	-	
MD Electric Vehicle Program Reg Asset excl. Res Direct		129,622							DISTPLTxRES-SUB
- Demand	DISTPLTxRES-SUB-D	129,622	-	34,694	896	77,900	15,917	215	100%
- Customer	DISTPLTxRES-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLTxRES-SUB-E	-	-	-	-	-	-	-	0%
Total		129,622	-	34,694	896	77,900	15,917	215	
MD EV Reg Asset - Residential Direct		165,486							DISTPLT-SUB
- Demand	Res-Direct	165,486	165,486	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		165,486	165,486	-	-	-	-	-	
Total Additional to Utility Plant		1,698,877							
- Demand		1,698,877	1,252,135	175,115	3,375	188,106	72,128	8,017	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,698,877	1,252,135	175,115	3,375	188,106	72,128	8,017	
Total Utility Plant		283,228,221							
- Demand		283,228,221	178,642,524	28,048,443	723,543	62,772,862	12,859,946	180,902	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**283,228,221**	**178,642,524**	**28,048,443**	**723,543**	**62,772,862**	**12,859,946**	**180,902**	
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
Distribution Plant A/D		(101,449,577)							DISTPLT-SUB
- Demand	DISTPLT-SUB-D	(101,449,577)	(63,922,928)	(10,044,201)	(259,514)	(22,552,523)	(4,608,112)	(62,299)	100%
- Customer	DISTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		(101,449,577)	(63,922,928)	(10,044,201)	(259,514)	(22,552,523)	(4,608,112)	(62,299)	
General Plant A/D		(4,804,789)							LABOR-SUB
- Demand	LABOR-SUB-D	(4,804,789)	(3,027,476)	(475,707)	(12,291)	(1,068,118)	(218,246)	(2,951)	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		(4,804,789)	(3,027,476)	(475,707)	(12,291)	(1,068,118)	(218,246)	(2,951)	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant A/D		(4,773,417)							LABOR-SUB
- Demand	LABOR-SUB-D	(4,773,417)	(3,007,709)	(472,601)	(12,211)	(1,061,144)	(216,821)	(2,931)	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		(4,773,417)	(3,007,709)	(472,601)	(12,211)	(1,061,144)	(216,821)	(2,931)	
COVID Reg Asset A/D		(140,377)							COVIDREGASSET-SUB
- Demand	COVIDREGASSET-SUB-D	(140,377)	(108,665)	(14,042)	(248)	(11,021)	(5,621)	(780)	100%
- Customer	COVIDREGASSET-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	COVIDREGASSET-SUB-E	-	-	-	-	-	-	-	0%
Total		(140,377)	(108,665)	(14,042)	(248)	(11,021)	(5,621)	(780)	
EV Reg Asset A/D		(29,511)							EVREGASSET-SUB
- Demand	EVREGASSET-SUB-D	(29,511)	(16,549)	(3,469)	(90)	(7,790)	(1,592)	(22)	100%
- Customer	EVREGASSET-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	EVREGASSET-SUB-E	-	-	-	-	-	-	-	0%
Total		(29,511)	(16,549)	(3,469)	(90)	(7,790)	(1,592)	(22)	
CWIP A/D		(31,435)							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	(31,435)	(19,828)	(3,113)	(80)	(6,967)	(1,427)	(20)	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		(31,435)	(19,828)	(3,113)	(80)	(6,967)	(1,427)	(20)	
Total Accumulated Depreciation		(111,229,107)							
- Demand		(111,229,107)	(70,103,155)	(11,013,134)	(284,433)	(24,707,563)	(5,051,820)	(69,003)	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total Accumulated Depreciation		**(111,229,107)**	**(70,103,155)**	**(11,013,134)**	**(284,433)**	**(24,707,563)**	**(5,051,820)**	**(69,003)**	
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Construction Work in Progress		9,717,881							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	9,717,881	6,129,427	962,374	24,826	2,153,808	441,239	6,207	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		9,717,881	6,129,427	962,374	24,826	2,153,808	441,239	6,207	
Plant Held for Future Use		-							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Prepayments		-							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Working Capital		3,158,071							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	3,158,071	1,991,912	312,748	8,068	699,934	143,392	2,017	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		3,158,071	1,991,912	312,748	8,068	699,934	143,392	2,017	
ADIT		(43,324,794)							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	(43,324,794)	(27,326,552)	(4,290,508)	(110,679)	(9,602,226)	(1,967,158)	(27,672)	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		(43,324,794)	(27,326,552)	(4,290,508)	(110,679)	(9,602,226)	(1,967,158)	(27,672)	
Customer Advances		(978,681)							DISTPLT-SUB
- Demand	DISTPLT-SUB-D	(978,681)	(616,663)	(96,896)	(2,504)	(217,564)	(44,454)	(601)	100%
- Customer	DISTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		(978,681)	(616,663)	(96,896)	(2,504)	(217,564)	(44,454)	(601)	
Customer Deposits		(2,694,811)							TOTPLT-SUB
- Demand	Deposits	(2,694,811)	(1,472,361)	(401,386)	-	(813,122)	-	(7,941)	100%
- Customer	Deposits	-	-	-	-	-	-	-	0%
- Commodity	Deposits	-	-	-	-	-	-	-	0%
Total		(2,694,811)	(1,472,361)	(401,386)	-	(813,122)	-	(7,941)	
Deferred Investment Tax Credit		-							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Total Other Rate Base Items		(34,122,334)							
- Demand		(34,122,334)	(21,294,236)	(3,513,669)	(80,289)	(7,779,169)	(1,426,981)	(27,991)	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		(34,122,334)	(21,294,236)	(3,513,669)	(80,289)	(7,779,169)	(1,426,981)	(27,991)	
Total Rate Base		**137,876,780**							
- Demand		**137,876,780**	**87,245,134**	**13,521,641**	**358,821**	**30,286,130**	**6,381,146**	**83,908**	
- Customer		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**137,876,780**	**87,245,134**	**13,521,641**	**358,821**	**30,286,130**	**6,381,146**	**83,908**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
OPERATIONS & MAINTENANCE EXPENSES									
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering		15,362							DistOpExp-SUB
- Demand	DistOpExp-SUB-D	15,362	9,680	1,521	39	3,415	698	9	100%
- Customer	DistOpExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-SUB-E	-	-	-	-	-	-	-	0%
Total		15,362	9,680	1,521	39	3,415	698	9	
(581) Load Dispatching		-							DEM
- Demand		-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(582) Station Expenses		-							DEM
- Demand		-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(583) Overhead line expenses		458,823							OHLines-SUB
- Demand	OHLines-SUB-D	458,823	289,102	45,427	1,174	101,998	20,841	282	100%
- Customer	OHLines-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	OHLines-SUB-E	-	-	-	-	-	-	-	0%
Total		458,823	289,102	45,427	1,174	101,998	20,841	282	
(584) Underground line expenses		406,189							UGLines-SUB
- Demand	UGLines-SUB-D	406,189	255,938	40,216	1,039	90,297	18,450	249	100%
- Customer	UGLines-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	UGLines-SUB-E	-	-	-	-	-	-	-	0%
Total		406,189	255,938	40,216	1,039	90,297	18,450	249	
(585) Street lighting and signal system expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(586) Meter expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(588) Miscellaneous distribution expenses		992,830							DistOpExp-SUB
- Demand	DistOpExp-SUB-D	992,830	625,578	98,297	2,540	220,709	45,097	610	100%
- Customer	DistOpExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-SUB-E	-	-	-	-	-	-	-	0%
Total		992,830	625,578	98,297	2,540	220,709	45,097	610	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(589) Rents		239,014							DistOpExp-SUB
- Demand	DistOpExp-SUB-D	239,014	150,602	23,664	611	53,134	10,857	147	100%
- Customer	DistOpExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-SUB-E	-	-	-	-	-	-	-	0%
Total		239,014	150,602	23,664	611	53,134	10,857	147	
Total Dist. Operations Expenses		2,112,218							
- Demand		2,112,218	1,330,899	209,124	5,403	469,552	95,943	1,297	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		2,112,218	1,330,899	209,124	5,403	469,552	95,943	1,297	
Maintenance Expense									
(590) Maintenance Supervision and Engineering		-							DistMtExp-SUB
- Demand	DistMtExp-SUB-D	-	-	-	-	-	-	-	100%
- Customer	DistMtExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(591) Maintenance of Structures		-							DistMtExp-SUB
- Demand	DistMtExp-SUB-D	-	-	-	-	-	-	-	100%
- Customer	DistMtExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(592) Maintenance of Station Equipment		-							DEM
- Demand		-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(593) Maintenance of Overhead Lines		6,790,371							OHLines-SUB
- Demand	OHLines-SUB-D	6,790,371	4,278,582	672,293	17,370	1,509,518	308,437	4,170	100%
- Customer	OHLines-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	OHLines-SUB-E	-	-	-	-	-	-	-	0%
Total		6,790,371	4,278,582	672,293	17,370	1,509,518	308,437	4,170	
(594) Maintenance of underground lines		264,639							UGLines-SUB
- Demand	UGLines-SUB-D	264,639	166,748	26,201	677	58,830	12,021	163	100%
- Customer	UGLines-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	UGLines-SUB-E	-	-	-	-	-	-	-	0%
Total		264,639	166,748	26,201	677	58,830	12,021	163	
(595) Maintenance of line transformers		-							DEM
- Demand	12CP-SUB	-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(596) Maintenance of street lighting and signal systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(597) Maintenance of meters		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(598) Maintenance of miscellaneous distribution plant		45,853							DistMtExp-SUB
- Demand	DistMtExp-SUB-D	45,853	28,892	4,540	117	10,193	2,083	28	100%
- Customer	DistMtExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-SUB-E	-	-	-	-	-	-	-	0%
Total		45,853	28,892	4,540	117	10,193	2,083	28	
Total Dist. Maintenance Expenses		7,100,863							
- Demand		7,100,863	4,474,222	703,034	18,164	1,578,542	322,540	4,361	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		7,100,863	4,474,222	703,034	18,164	1,578,542	322,540	4,361	
Total Distribution Expenses		9,213,081							
- Demand		9,213,081	5,805,122	912,158	23,568	2,048,094	418,483	5,658	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		9,213,081	5,805,122	912,158	23,568	2,048,094	418,483	5,658	
Customer Accounts and Services									
Meter Reading & Billing		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Other-Direct to Other		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Uncollectibles		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Misc. Cust Serv and Info Exp		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Rebates & Incentives		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Assistance		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Sales Expense		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
All Other Cust Accts & Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Customer Accounts and Services		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Administrative & General Expense									
Administrative and General Salaries		662,957							NONAGLAB-SUB
- Demand	NONAGLAB-SUB-D	662,957	417,726	65,637	1,696	147,377	30,113	407	100%
- Customer	NONAGLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		662,957	417,726	65,637	1,696	147,377	30,113	407	
Outside Services		1,276,426							NONAGLAB-SUB
- Demand	NONAGLAB-SUB-D	1,276,426	804,270	126,375	3,265	283,753	57,979	784	100%
- Customer	NONAGLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		1,276,426	804,270	126,375	3,265	283,753	57,979	784	
Employee Benefits (Acct. 926)		(395,698)							NONAGLAB-SUB
- Demand	NONAGLAB-SUB-D	(395,698)	(249,328)	(39,177)	(1,012)	(87,965)	(17,974)	(243)	100%
- Customer	NONAGLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		(395,698)	(249,328)	(39,177)	(1,012)	(87,965)	(17,974)	(243)	
Regulatory Commission Expenses (Acct 928)		256,418							DISTPLT-SUB
- Demand	SalesREV	256,418	163,498	47,621	816	32,211	2,002	10,271	100%
- Customer	SalesREV	-	-	-	-	-	-	-	0%
- Commodity	SalesREV	-	-	-	-	-	-	-	0%
Total		256,418	163,498	47,621	816	32,211	2,002	10,271	
General Advertising Expense		9,404							OpExp-SUB
- Demand	OpExp-SUB-D	9,404	5,925	931	24	2,091	427	6	100%
- Customer	OpExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	OpExp-SUB-E	-	-	-	-	-	-	-	0%
Total		9,404	5,925	931	24	2,091	427	6	
All Other O&M		359,987							NONAGLAB-SUB
- Demand	NONAGLAB-SUB-D	359,987	226,826	35,641	921	80,026	16,352	221	100%
- Customer	NONAGLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		359,987	226,826	35,641	921	80,026	16,352	221	
Total A&G Expense		2,169,494							
- Demand		2,169,494	1,368,918	237,028	5,710	457,493	88,899	11,446	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		2,169,494	1,368,918	237,028	5,710	457,493	88,899	11,446	
Total O&M Expenses		11,382,575							
- Demand		11,382,575	7,174,040	1,149,186	29,278	2,505,586	507,382	17,104	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**11,382,575**	**7,174,040**	**1,149,186**	**29,278**	**2,505,586**	**507,382**	**17,104**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
DEPRECIATION EXPENSE									
Depreciation Expense									
Distribution Plant DeprExp		5,548,472							DISTPLT-SUB
- Demand	DISTPLT-SUB-D	5,548,472	3,496,067	549,337	14,193	1,233,441	252,026	3,407	100%
- Customer	DISTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		5,548,472	3,496,067	549,337	14,193	1,233,441	252,026	3,407	
General Plant DeprExp		514,833							LABOR-SUB
- Demand	LABOR-SUB-D	514,833	324,394	50,972	1,317	114,449	23,385	316	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		514,833	324,394	50,972	1,317	114,449	23,385	316	
Intangible Plant DeprExp		421,170							LABOR-SUB
- Demand	LABOR-SUB-D	421,170	265,377	41,699	1,077	93,627	19,131	259	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		421,170	265,377	41,699	1,077	93,627	19,131	259	
Total Depreciation Expenses		6,484,474							
- Demand		6,484,474	4,085,839	642,007	16,588	1,441,517	294,542	3,982	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**6,484,474**	**4,085,839**	**642,007**	**16,588**	**1,441,517**	**294,542**	**3,982**	
Regulatory Debits and Credits									
MD EDIS		(75,618)							DEM
- Demand	1NCP-PRI	(75,618)	(46,404)	(10,154)	(299)	(18,150)	(161)	(450)	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		(75,618)	(46,404)	(10,154)	(299)	(18,150)	(161)	(450)	
MD Electric Vehicle Program		58,655							EVREGASSET-SUB
- Demand	EVREGASSET-SUB-D	58,655	32,892	6,896	178	15,483	3,164	43	100%
- Customer	EVREGASSET-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	EVREGASSET-SUB-E	-	-	-	-	-	-	-	0%
Total		58,655	32,892	6,896	178	15,483	3,164	43	
MD Conservation Voltage Reduction (CVR)		-							DISTPLT-SUB
- Demand	DISTPLT-SUB-D	-	-	-	-	-	-	-	100%
- Customer	DISTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Deferral of Rate Case Expenses		(14,490)							DISTPLT-SUB
- Demand	DISTPLT-SUB-D	(14,490)	(9,130)	(1,435)	(37)	(3,221)	(658)	(9)	100%
- Customer	DISTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		(14,490)	(9,130)	(1,435)	(37)	(3,221)	(658)	(9)	
COVID-19		373,228							DISTPLT-SUB
- Demand	COVID	373,228	309,804	28,084	496	22,041	11,242	1,560	100%
- Customer	COVID	-	-	-	-	-	-	-	0%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		373,228	309,804	28,084	496	22,041	11,242	1,560	
COVID-19 - Residential Adjustment		(92,475)							DISTPLT-SUB
- Demand	Res-Direct	(92,475)	(92,475)	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(92,475)	(92,475)	-	-	-	-	-	
Total Regulatory Debits and Credits		249,300							
- Demand		249,300	194,687	23,391	338	16,153	13,587	1,144	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		249,300	194,687	23,391	338	16,153	13,587	1,144	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Taxes Other than Income									
Distribution Payroll Taxes		131,591							DISTLAB-SUB
- Demand	DISTLAB-SUB-D	131,591	82,915	13,028	337	29,253	5,977	81	100%
- Customer	DISTLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		131,591	82,915	13,028	337	29,253	5,977	81	
Customer Account Payroll Taxes		-							CUSTLAB-SUB
- Demand	CUSTLAB-SUB-D	-	-	-	-	-	-	-	0%
- Customer	CUSTLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	CUSTLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
A&G Payroll Taxes		2,225							AGLAB-SUB
- Demand	AGLAB-SUB-D	2,225	1,402	220	6	495	101	1	100%
- Customer	AGLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	AGLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		2,225	1,402	220	6	495	101	1	
Gross Receipt Taxes		1,336,493							TOTPLT-SUB
- Demand	Revenue	1,336,493	830,618	245,612	4,336	192,763	13,688	49,475	100%
- Customer	Revenue	-	-	-	-	-	-	-	0%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		1,336,493	830,618	245,612	4,336	192,763	13,688	49,475	
Property Taxes		2,590,216							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	2,590,216	1,633,745	256,512	6,617	574,079	117,608	1,654	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		2,590,216	1,633,745	256,512	6,617	574,079	117,608	1,654	
Sales & Use Tax		(38,907)							TOTPLT-SUB
- Demand	Revenue	(38,907)	(24,181)	(7,150)	(126)	(5,612)	(398)	(1,440)	100%
- Customer	Revenue	-	-	-	-	-	-	-	0%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		(38,907)	(24,181)	(7,150)	(126)	(5,612)	(398)	(1,440)	
Montgomery County Fuel Energy		1,827,420							TOTPLT-SUB
- Demand	MontCoFuel	1,827,420	874,235	332,916	7,158	586,896	-	26,215	100%
- Customer	MontCoFuel	-	-	-	-	-	-	-	0%
- Commodity	MontCoFuel	-	-	-	-	-	-	-	0%
Total		1,827,420	874,235	332,916	7,158	586,896	-	26,215	
Other Taxes		124							RB-SUB
- Demand	RB-SUB-D	124	78	12	0	27	6	0	100%
- Customer	RB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	RB-SUB-E	-	-	-	-	-	-	-	0%
Total		124	78	12	0	27	6	0	
Total Taxes Other than Income		5,849,161							
- Demand		5,849,161	3,398,814	841,151	18,327	1,377,902	136,982	75,986	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total Taxes Other than Income		5,849,161	3,398,814	841,151	18,327	1,377,902	136,982	75,986	
Total Operating Expenses		**23,965,511**							
- Demand		**23,965,511**	**14,853,379**	**2,655,736**	**64,530**	**5,341,157**	**952,493**	**98,215**	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**23,965,511**	**14,853,379**	**2,655,736**	**64,530**	**5,341,157**	**952,493**	**98,215**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
UTILITY PLANT									
Distribution Plant									
(360) Land and Land Rights		12,433,259							360P
- Demand	1NCP-PRI	12,247,291	7,515,677	1,644,569	48,427	2,939,694	26,029	72,895	99%
- Customer	Customers-PRI	185,968	163,736	20,396	212	1,093	1	529	1%
- Commodity		-	-	-	-	-	-	-	0%
Total		12,433,259	7,679,413	1,664,966	48,640	2,940,787	26,030	73,424	
(361) Structures and Improvements		11,481,863							DEM
- Demand	1NCP-PRI	11,481,863	7,045,964	1,541,787	45,401	2,755,970	24,402	68,340	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		11,481,863	7,045,964	1,541,787	45,401	2,755,970	24,402	68,340	
(362) Station Equipment		189,192,334							DEM
- Demand	1NCP-PRI	189,192,334	116,099,828	25,404,792	748,090	45,411,471	402,088	1,126,064	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		189,192,334	116,099,828	25,404,792	748,090	45,411,471	402,088	1,126,064	
(362) Station Equipment - Capacitors		-							DEM
- Demand		-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(364) Poles, Towers & Fixtures		5,330,296							364P
- Demand	1NCP-PRI	3,888,518	2,386,229	522,151	15,376	933,354	8,264	23,144	73%
- Customer	Customers-PRI	1,441,778	1,269,423	158,131	1,646	8,475	5	4,098	27%
- Commodity		-	-	-	-	-	-	-	0%
Total		5,330,296	3,655,652	680,282	17,022	941,828	8,269	27,242	
(365) Overhead Conductors & Devices		7,476,890							365P
- Demand	1NCP-PRI	4,235,205	2,598,977	568,704	16,747	1,016,568	9,001	25,208	57%
- Customer	Customers-PRI	3,241,684	2,854,162	355,540	3,702	19,055	11	9,214	43%
- Commodity		-	-	-	-	-	-	-	0%
Total		7,476,890	5,453,139	924,245	20,448	1,035,623	9,012	34,422	
(366) Underground Conduit		2,567,410							366P
- Demand	1NCP-PRI	2,567,410	1,575,517	344,752	10,152	616,250	5,456	15,281	100%
- Customer	Customers-PRI	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		2,567,410	1,575,517	344,752	10,152	616,250	5,456	15,281	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(367) Underground Conductors & Device		4,855,228							367P
- Demand	1NCP-PRI	2,431,427	1,492,070	326,493	9,614	583,611	5,167	14,472	50%
- Customer	Customers-PRI	2,423,801	2,134,052	265,837	2,768	14,247	9	6,889	50%
- Commodity		-	-	-	-	-	-	-	0%
Total		4,855,228	3,626,122	592,329	12,382	597,858	5,176	21,361	
(368) Line Transformers		347,087							368P
- Demand	1NCP-PRI	243,699	149,548	32,724	964	58,495	518	1,450	70%
- Customer	Customers-PRI	103,388	91,028	11,339	118	608	0	294	30%
- Commodity		-	-	-	-	-	-	-	0%
Total		347,087	240,577	44,063	1,082	59,102	518	1,744	
(368) Line Transformers - Capacitors		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(369) Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(370, 371) Meters and Installation		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Street Lighting & Signal Systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Distribution Plant		233,684,367							
- Demand		226,287,748	138,863,812	30,385,973	894,770	54,315,412	480,927	1,346,854	
- Customer		7,396,619	6,512,401	811,243	8,446	43,478	26	21,024	
- Commodity		-	-	-	-	-	-	-	
Total		233,684,367	145,376,213	31,197,217	903,216	54,358,890	480,953	1,367,879	
General and Intangible Plant									
General Plant		9,175,889							LABOR-PRI
- Demand	LABOR-PRI-D	8,879,259	5,448,849	1,192,309	35,110	2,131,271	18,871	52,849	97%
- Customer	LABOR-PRI-C	296,630	261,170	32,534	339	1,744	1	843	3%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		9,175,889	5,710,019	1,224,843	35,448	2,133,015	18,872	53,692	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant		5,743,286							LABOR-PRI
- Demand	LABOR-PRI-D	5,557,622	3,410,492	746,279	21,976	1,333,985	11,812	33,079	97%
- Customer	LABOR-PRI-C	185,664	163,469	20,363	212	1,091	1	528	3%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		5,743,286	3,573,961	766,642	22,188	1,335,077	11,812	33,606	
Total General and Intangible Plant		14,919,176							
- Demand		14,436,881	8,859,341	1,938,588	57,085	3,465,257	30,683	85,928	
- Customer		482,294	424,639	52,897	551	2,835	2	1,371	
- Commodity		-	-	-	-	-	-	-	
Total		14,919,176	9,283,980	1,991,485	57,636	3,468,092	30,684	87,299	
Additions to Utility Plant									
COVID-19 Regulatory Asset Adj excl. Res Adj		1,645,874							DISTPLT-PRI
- Demand	COVID	1,593,778	1,322,942	119,927	2,117	94,122	48,007	6,663	97%
- Customer	COVID	52,095	43,243	3,920	69	3,077	1,569	218	3%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		1,645,874	1,366,185	123,847	2,186	97,199	49,576	6,881	
COVID-19 Residential Adjustment		(407,797)							DISTPLT-PRI
- Demand	Res-Direct	(394,890)	(394,890)	-	-	-	-	-	97%
- Customer	Res-Direct	(12,908)	(12,908)	-	-	-	-	-	3%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(407,797)	(407,797)	-	-	-	-	-	
MD Electric Vehicle Program Reg Asset excl. Res Direct		114,323							DISTPLTxRES-PRI
- Demand	DISTPLTxRES-PRI-D	113,178	-	39,337	1,158	70,316	623	1,744	99%
- Customer	DISTPLTxRES-PRI-C	1,145	-	1,050	11	56	0	27	1%
- Commodity	DISTPLTxRES-PRI-E	-	-	-	-	-	-	-	0%
Total		114,323	-	40,388	1,169	70,372	623	1,771	
MD EV Reg Asset - Residential Direct		145,953							DISTPLT-PRI
- Demand	Res-Direct	141,334	141,334	-	-	-	-	-	97%
- Customer	Res-Direct	4,620	4,620	-	-	-	-	-	3%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		145,953	145,953	-	-	-	-	-	
Total Additional to Utility Plant		1,498,352							
- Demand		1,453,400	1,069,386	159,264	3,276	164,438	48,630	8,406	
- Customer		44,952	34,955	4,970	80	3,133	1,569	245	
- Commodity		-	-	-	-	-	-	-	
Total		1,498,352	1,104,341	164,234	3,356	167,571	50,199	8,651	
Total Utility Plant		250,101,895							
- Demand		242,178,029	148,792,539	32,483,825	955,131	57,945,107	560,239	1,441,188	
- Customer		7,923,866	6,971,995	869,111	9,077	49,446	1,597	22,640	
- Commodity		-	-	-	-	-	-	-	
Total		**250,101,895**	**155,764,534**	**33,352,936**	**964,208**	**57,994,552**	**561,836**	**1,463,829**	
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
Distribution Plant A/D		(89,475,128)							DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(86,643,046)	(53,169,399)	(11,634,449)	(342,597)	(20,796,763)	(184,142)	(515,695)	97%
- Customer	DISTPLT-PRI-C	(2,832,083)	(2,493,525)	(310,616)	(3,234)	(16,647)	(10)	(8,050)	3%
- Commodity	DISTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		(89,475,128)	(55,662,924)	(11,945,065)	(345,831)	(20,813,410)	(184,151)	(523,745)	
General Plant A/D		(4,325,836)							LABOR-PRI
- Demand	LABOR-PRI-D	(4,185,994)	(2,568,778)	(562,096)	(16,552)	(1,004,756)	(8,896)	(24,915)	97%
- Customer	LABOR-PRI-C	(139,842)	(123,125)	(15,338)	(160)	(822)	(0)	(397)	3%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		(4,325,836)	(2,691,903)	(577,434)	(16,712)	(1,005,578)	(8,897)	(25,312)	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant A/D		(4,209,994)							LABOR-PRI
- Demand	LABOR-PRI-D	(4,073,897)	(2,499,989)	(547,044)	(16,109)	(977,850)	(8,658)	(24,248)	97%
- Customer	LABOR-PRI-C	(136,097)	(119,828)	(14,927)	(155)	(800)	(0)	(387)	3%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		(4,209,994)	(2,619,816)	(561,971)	(16,264)	(978,650)	(8,659)	(24,634)	
COVID Reg Asset A/D		(123,808)							COVIDREGASSET-PRI
- Demand	COVIDREGASSET-PRI-D	(119,889)	(92,805)	(11,993)	(212)	(9,412)	(4,801)	(666)	97%
- Customer	COVIDREGASSET-PRI-C	(3,919)	(3,034)	(392)	(7)	(308)	(157)	(22)	3%
- Commodity	COVIDREGASSET-PRI-E	-	-	-	-	-	-	-	0%
Total		(123,808)	(95,839)	(12,385)	(219)	(9,720)	(4,958)	(688)	
EV Reg Asset A/D		(26,028)							EVREGASSET-PRI
- Demand	EVREGASSET-PRI-D	(25,451)	(14,133)	(3,934)	(116)	(7,032)	(62)	(174)	98%
- Customer	EVREGASSET-PRI-C	(576)	(462)	(105)	(1)	(6)	(0)	(3)	2%
- Commodity	EVREGASSET-PRI-E	-	-	-	-	-	-	-	0%
Total		(26,028)	(14,595)	(4,039)	(117)	(7,037)	(62)	(177)	
CWIP A/D		(27,725)							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	(26,847)	(16,494)	(3,601)	(106)	(6,424)	(62)	(160)	97%
- Customer	TOTPLT-PRI-C	(878)	(773)	(96)	(1)	(5)	(0)	(3)	3%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		(27,725)	(17,267)	(3,697)	(107)	(6,429)	(62)	(162)	
Total Accumulated Depreciation		(98,188,518)							
- Demand		(95,075,123)	(58,361,599)	(12,763,116)	(375,692)	(22,802,236)	(206,621)	(565,858)	
- Customer		(3,113,395)	(2,740,746)	(341,474)	(3,558)	(18,588)	(168)	(8,861)	
- Commodity		-	-	-	-	-	-	-	
Total Accumulated Depreciation		**(98,188,518)**	**(61,102,345)**	**(13,104,590)**	**(379,250)**	**(22,820,824)**	**(206,789)**	**(574,720)**	
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Construction Work in Progress		8,581,279							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	8,309,402	5,105,240	1,114,557	32,772	1,988,162	19,222	49,449	97%
- Customer	TOTPLT-PRI-C	271,877	239,217	29,820	311	1,697	55	777	3%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		8,581,279	5,344,457	1,144,377	33,083	1,989,859	19,277	50,226	
Plant Held for Future Use		-							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	-	-	-	-	-	-	-	97%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-	3%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Prepayments		-							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	-	-	-	-	-	-	-	97%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-	3%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Working Capital		2,788,703							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	2,700,350	1,659,077	362,203	10,650	646,104	6,247	16,070	97%
- Customer	TOTPLT-PRI-C	88,353	77,740	9,691	101	551	18	252	3%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		2,788,703	1,736,816	371,894	10,751	646,655	6,265	16,322	
ADIT		(38,257,533)							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	(37,045,437)	(22,760,465)	(4,968,979)	(146,104)	(8,863,735)	(85,699)	(220,455)	97%
- Customer	TOTPLT-PRI-C	(1,212,096)	(1,066,491)	(132,946)	(1,388)	(7,564)	(244)	(3,463)	3%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		(38,257,533)	(23,826,956)	(5,101,925)	(147,493)	(8,871,298)	(85,943)	(223,919)	
Customer Advances		(863,164)							DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(835,843)	(512,924)	(112,237)	(3,305)	(200,626)	(1,776)	(4,975)	97%
- Customer	DISTPLT-PRI-C	(27,321)	(24,055)	(2,997)	(31)	(161)	(0)	(78)	3%
- Commodity	DISTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		(863,164)	(536,979)	(115,234)	(3,336)	(200,786)	(1,777)	(5,053)	
Customer Deposits		(2,379,626)							TOTPLT-PRI
- Demand	Deposits	(2,304,233)	(1,258,962)	(343,211)	-	(695,270)	-	(6,790)	97%
- Customer	Deposits	(75,393)	(41,192)	(11,230)	-	(22,749)	-	(222)	3%
- Commodity	Deposits	-	-	-	-	-	-	-	0%
Total		(2,379,626)	(1,300,154)	(354,440)	-	(718,019)	-	(7,013)	
Deferred Investment Tax Credit		-							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	-	-	-	-	-	-	-	97%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-	3%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Total Other Rate Base Items		(30,130,341)							
- Demand		(29,175,761)	(17,768,034)	(3,947,666)	(105,988)	(7,125,365)	(62,006)	(166,702)	
- Customer		(954,580)	(814,781)	(107,661)	(1,007)	(28,225)	(172)	(2,734)	
- Commodity		-	-	-	-	-	-	-	
Total		(30,130,341)	(18,582,815)	(4,055,327)	(106,995)	(7,153,590)	(62,177)	(169,436)	
Total Rate Base		**121,783,036**							
- Demand		**117,927,146**	**72,662,906**	**15,773,042**	**473,452**	**28,017,505**	**291,612**	**708,628**	
- Customer		**3,855,891**	**3,416,468**	**419,976**	**4,512**	**2,633**	**1,257**	**11,045**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**121,783,036**	**76,079,374**	**16,193,018**	**477,964**	**28,020,138**	**292,869**	**719,673**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
OPERATIONS & MAINTENANCE EXPENSES									

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering		3,402							DistOpExp-PRI
- Demand	DistOpExp-PRI-D	3,000	1,841	403	12	720	6	18	88%
- Customer	DistOpExp-PRI-C	402	354	44	0	2	0	1	12%
- Commodity	DistOpExp-PRI-E	-	-	-	-	-	-	-	0%
Total		3,402	2,195	447	12	723	6	19	
(581) Load Dispatching		116,085							DEM
- Demand	1NCP-PRI	116,085	71,237	15,588	459	27,864	247	691	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		116,085	71,237	15,588	459	27,864	247	691	
(582) Station Expenses		16,885							DEM
- Demand	1NCP-PRI	16,885	10,362	2,267	67	4,053	36	101	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		16,885	10,362	2,267	67	4,053	36	101	
(583) Overhead line expenses		32,702							OHLines-PRI
- Demand	OHLines-PRI-D	18,524	11,367	2,487	73	4,446	39	110	57%
- Customer	OHLines-PRI-C	14,178	12,483	1,555	16	83	0	40	43%
- Commodity	OHLines-PRI-E	-	-	-	-	-	-	-	0%
Total		32,702	23,850	4,042	89	4,530	39	151	
(584) Underground line expenses		25,908							UGLines-PRI
- Demand	UGLines-PRI-D	17,448	10,707	2,343	69	4,188	37	104	67%
- Customer	UGLines-PRI-C	8,460	7,449	928	10	50	0	24	33%
- Commodity	UGLines-PRI-E	-	-	-	-	-	-	-	0%
Total		25,908	18,156	3,271	79	4,238	37	128	
(585) Street lighting and signal system expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(586) Meter expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(588) Miscellaneous distribution expenses		219,890							DistOpExp-PRI
- Demand	DistOpExp-PRI-D	193,906	118,993	26,038	767	46,543	412	1,154	88%
- Customer	DistOpExp-PRI-C	25,983	22,877	2,850	30	153	0	74	12%
- Commodity	DistOpExp-PRI-E	-	-	-	-	-	-	-	0%
Total		219,890	141,870	28,888	796	46,696	412	1,228	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(589) Rents		52,936							DistOpExp-PRI
- Demand	DistOpExp-PRI-D	46,681	28,646	6,268	185	11,205	99	278	88%
- Customer	DistOpExp-PRI-C	6,255	5,507	686	7	37	0	18	12%
- Commodity	DistOpExp-PRI-E	-	-	-	-	-	-	-	0%
Total		52,936	34,154	6,954	192	11,242	99	296	
Total Dist. Operations Expenses		467,809							
- Demand		412,530	253,153	55,395	1,631	99,019	877	2,455	
- Customer		55,279	48,671	6,063	63	325	0	157	
- Commodity		-	-	-	-	-	-	-	
Total		467,809	301,824	61,458	1,694	99,344	877	2,612	
Maintenance Expense									
(590) Maintenance Supervision and Engineering		-							DistMtExp-PRI
- Demand	DistMtExp-PRI-D	-	-	-	-	-	-	-	93%
- Customer	DistMtExp-PRI-C	-	-	-	-	-	-	-	7%
- Commodity	DistMtExp-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(591) Maintenance of Structures		-							DistMtExp-PRI
- Demand	DistMtExp-PRI-D	-	-	-	-	-	-	-	93%
- Customer	DistMtExp-PRI-C	-	-	-	-	-	-	-	7%
- Commodity	DistMtExp-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(592) Maintenance of Station Equipment		2,539,262							DEM
- Demand	1NCP-PRI	2,539,262	1,558,244	340,973	10,041	609,494	5,397	15,114	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		2,539,262	1,558,244	340,973	10,041	609,494	5,397	15,114	
(593) Maintenance of Overhead Lines		483,972							OHLines-PRI
- Demand	OHLines-PRI-D	274,141	168,229	36,812	1,084	65,801	583	1,632	57%
- Customer	OHLines-PRI-C	209,831	184,747	23,014	240	1,233	1	596	43%
- Commodity	OHLines-PRI-E	-	-	-	-	-	-	-	0%
Total		483,972	352,976	59,825	1,324	67,035	583	2,228	
(594) Maintenance of underground lines		16,880							UGLines-PRI
- Demand	UGLines-PRI-D	11,368	6,976	1,526	45	2,729	24	68	67%
- Customer	UGLines-PRI-C	5,512	4,853	605	6	32	0	16	33%
- Commodity	UGLines-PRI-E	-	-	-	-	-	-	-	0%
Total		16,880	11,829	2,131	51	2,761	24	83	
(595) Maintenance of line transformers		174							368P
- Demand	1NCP-PRI	122	75	16	0	29	0	1	70%
- Customer	Customers-PRI	52	46	6	0	0	0	0	30%
- Commodity		-	-	-	-	-	-	-	0%
Total		174	120	22	1	30	0	1	
(596) Maintenance of street lighting and signal systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(597) Maintenance of meters		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(598) Maintenance of miscellaneous distribution plant		19,760							DistMtExp-PRI
- Demand	DistMtExp-PRI-D	18,360	11,267	2,465	73	4,407	39	109	93%
- Customer	DistMtExp-PRI-C	1,400	1,233	154	2	8	0	4	7%
- Commodity	DistMtExp-PRI-E	-	-	-	-	-	-	-	0%
Total		19,760	12,499	2,619	74	4,415	39	113	
Total Dist. Maintenance Expenses		3,060,047							
- Demand		2,843,252	1,744,791	381,793	11,243	682,460	6,043	16,923	
- Customer		216,795	190,878	23,778	248	1,274	1	616	
- Commodity		-	-	-	-	-	-	-	
Total		3,060,047	1,935,669	405,570	11,490	683,735	6,043	17,539	
Total Distribution Expenses		3,527,856							
- Demand		3,255,782	1,997,944	437,187	12,874	781,479	6,919	19,378	
- Customer		272,074	239,549	29,840	311	1,599	1	773	
- Commodity		-	-	-	-	-	-	-	
Total		3,527,856	2,237,494	467,028	13,184	783,078	6,920	20,152	
Customer Accounts and Services									
Meter Reading & Billing		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Other-Direct to Other		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Uncollectibles		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Misc. Cust Serv and Info Exp		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Rebates & Incentives		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Assistance		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Sales Expense		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
All Other Cust Accts & Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Customer Accounts and Services		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Administrative & General Expense									
Administrative and General Salaries		596,871							NONAGLAB-PRI
- Demand	NONAGLAB-PRI-D	577,576	354,436	77,557	2,284	138,634	1,228	3,438	97%
- Customer	NONAGLAB-PRI-C	19,295	16,989	2,116	22	113	0	55	3%
- Commodity	NONAGLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		596,871	371,424	79,673	2,306	138,748	1,228	3,493	
Outside Services		1,149,188							NONAGLAB-PRI
- Demand	NONAGLAB-PRI-D	1,112,038	682,414	149,325	4,397	266,920	2,363	6,619	97%
- Customer	NONAGLAB-PRI-C	37,150	32,709	4,075	42	218	0	106	3%
- Commodity	NONAGLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		1,149,188	715,123	153,399	4,440	267,139	2,364	6,724	
Employee Benefits (Acct. 926)		(356,254)							NONAGLAB-PRI
- Demand	NONAGLAB-PRI-D	(344,737)	(211,551)	(46,291)	(1,363)	(82,747)	(733)	(2,052)	97%
- Customer	NONAGLAB-PRI-C	(11,517)	(10,140)	(1,263)	(13)	(68)	(0)	(33)	3%
- Commodity	NONAGLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		(356,254)	(221,691)	(47,555)	(1,376)	(82,814)	(733)	(2,085)	
Regulatory Commission Expenses (Acct 928)		226,152							DISTPLT-PRI
- Demand	SalesREV	218,994	139,635	40,670	697	27,510	1,710	8,772	97%
- Customer	SalesREV	7,158	4,564	1,329	23	899	56	287	3%
- Commodity	SalesREV	-	-	-	-	-	-	-	0%
Total		226,152	144,200	42,000	720	28,409	1,765	9,059	
General Advertising Expense		3,601							OpExp-PRI
- Demand	OpExp-PRI-D	3,323	2,039	446	13	798	7	20	92%
- Customer	OpExp-PRI-C	278	245	30	0	2	0	1	8%
- Commodity	OpExp-PRI-E	-	-	-	-	-	-	-	0%
Total		3,601	2,284	477	13	799	7	21	
All Other O&M		324,103							NONAGLAB-PRI
- Demand	NONAGLAB-PRI-D	313,625	192,460	42,114	1,240	75,279	667	1,867	97%
- Customer	NONAGLAB-PRI-C	10,477	9,225	1,149	12	62	0	30	3%
- Commodity	NONAGLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		324,103	201,684	43,263	1,252	75,341	667	1,896	
Total A&G Expense		1,943,662							
- Demand		1,880,820	1,159,432	263,821	7,268	426,395	5,241	18,663	
- Customer		62,842	53,591	7,437	86	1,227	56	445	
- Commodity		-	-	-	-	-	-	-	
Total		1,943,662	1,213,023	271,257	7,355	427,621	5,297	19,108	
Total O&M Expenses		5,471,518							
- Demand		5,136,602	3,157,376	701,008	20,142	1,207,874	12,161	38,041	
- Customer		334,916	293,140	37,277	397	2,826	57	1,218	
- Commodity		-	-	-	-	-	-	-	
Total		**5,471,518**	**3,450,517**	**738,285**	**20,539**	**1,210,699**	**12,218**	**39,260**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
DEPRECIATION EXPENSE									
Depreciation Expense									
Distribution Plant DeprExp		4,893,566							DISTPLT-PRI
- Demand	DISTPLT-PRI-D	4,738,674	2,907,936	636,310	18,737	1,137,415	10,071	28,204	97%
- Customer	DISTPLT-PRI-C	154,892	136,376	16,988	177	910	1	440	3%
- Commodity	DISTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		4,893,566	3,044,312	653,298	18,914	1,138,325	10,072	28,645	
General Plant DeprExp		463,513							LABOR-PRI
- Demand	LABOR-PRI-D	448,529	275,244	60,229	1,774	107,660	953	2,670	97%
- Customer	LABOR-PRI-C	14,984	13,193	1,643	17	88	0	43	3%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		463,513	288,437	61,872	1,791	107,748	953	2,712	
Intangible Plant DeprExp		371,458							LABOR-PRI
- Demand	LABOR-PRI-D	359,450	220,580	48,267	1,421	86,278	764	2,139	97%
- Customer	LABOR-PRI-C	12,008	10,573	1,317	14	71	0	34	3%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		371,458	231,153	49,584	1,435	86,349	764	2,174	
Total Depreciation Expenses		5,728,537							
- Demand		5,546,653	3,403,761	744,806	21,932	1,331,352	11,788	33,013	
- Customer		181,884	160,141	19,949	208	1,069	1	517	
- Commodity		-	-	-	-	-	-	-	
Total		**5,728,537**	**3,563,902**	**764,754**	**22,140**	**1,332,421**	**11,789**	**33,530**	
Regulatory Debits and Credits									
MD EDIS		(66,774)							DEM
- Demand	1NCP-PRI	(66,774)	(40,976)	(8,966)	(264)	(16,028)	(142)	(397)	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		(66,774)	(40,976)	(8,966)	(264)	(16,028)	(142)	(397)	
MD Electric Vehicle Program		51,795							EVREGASSET-PRI
- Demand	EVREGASSET-PRI-D	50,648	28,125	7,828	231	13,993	124	347	98%
- Customer	EVREGASSET-PRI-C	1,147	919	209	2	11	0	5	2%
- Commodity	EVREGASSET-PRI-E	-	-	-	-	-	-	-	0%
Total		51,795	29,045	8,037	233	14,004	124	352	
MD Conservation Voltage Reduction (CVR)		-							DISTPLT-PRI
- Demand	DISTPLT-PRI-D	-	-	-	-	-	-	-	97%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-	3%
- Commodity	DISTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Deferral of Rate Case Expenses		(12,796)							DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(12,391)	(7,604)	(1,664)	(49)	(2,974)	(26)	(74)	97%
- Customer	DISTPLT-PRI-C	(405)	(357)	(44)	(0)	(2)	(0)	(1)	3%
- Commodity	DISTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		(12,796)	(7,960)	(1,708)	(49)	(2,976)	(26)	(75)	
COVID-19		329,175							DISTPLT-PRI
- Demand	COVID	318,756	264,588	23,985	423	18,824	9,601	1,333	97%
- Customer	COVID	10,419	8,649	784	14	615	314	44	3%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		329,175	273,237	24,769	437	19,440	9,915	1,376	
COVID-19 - Residential Adjustment		(81,559)							DISTPLT-PRI
- Demand	Res-Direct	(78,978)	(78,978)	-	-	-	-	-	97%
- Customer	Res-Direct	(2,582)	(2,582)	-	-	-	-	-	3%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(81,559)	(81,559)	-	-	-	-	-	
Total Regulatory Debits and Credits		219,841							
- Demand		211,261	165,156	21,183	341	13,816	9,557	1,208	
- Customer		8,580	6,630	949	16	624	314	48	
- Commodity		-	-	-	-	-	-	-	
Total		219,841	171,785	22,132	356	14,440	9,871	1,256	
Taxes Other than Income									
Distribution Payroll Taxes		118,474							DISTLAB-PRI
- Demand	DISTLAB-PRI-D	114,644	70,353	15,394	453	27,518	244	682	97%
- Customer	DISTLAB-PRI-C	3,830	3,372	420	4	23	0	11	3%
- Commodity	DISTLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		118,474	73,725	15,814	458	27,540	244	693	
Customer Account Payroll Taxes		-							CUSTLAB-PRI
- Demand	CUSTLAB-PRI-D	-	-	-	-	-	-	-	0%
- Customer	CUSTLAB-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	CUSTLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
A&G Payroll Taxes		2,003							AGLAB-PRI
- Demand	AGLAB-PRI-D	1,938	1,189	260	8	465	4	12	97%
- Customer	AGLAB-PRI-C	65	57	7	0	0	0	0	3%

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
- Commodity	AGLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		2,003	1,246	267	8	466	4	12	
Gross Receipt Taxes		1,180,177							TOTPLT-PRI
- Demand	Revenue	1,142,786	710,231	210,014	3,708	164,825	11,704	42,304	97%
- Customer	Revenue	37,391	23,238	6,871	121	5,393	383	1,384	3%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		1,180,177	733,469	216,885	3,829	170,218	12,087	43,688	
Property Taxes		2,287,264							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	2,214,798	1,360,757	297,075	8,735	529,927	5,124	13,180	97%
- Customer	TOTPLT-PRI-C	72,466	63,761	7,948	83	452	15	207	3%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		2,287,264	1,424,518	305,024	8,818	530,379	5,138	13,387	
Sales & Use Tax		(34,357)							TOTPLT-PRI
- Demand	Revenue	(33,268)	(20,676)	(6,114)	(108)	(4,798)	(341)	(1,232)	97%
- Customer	Revenue	(1,089)	(676)	(200)	(4)	(157)	(11)	(40)	3%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		(34,357)	(21,352)	(6,314)	(111)	(4,955)	(352)	(1,272)	
Montgomery County Fuel Energy		1,613,685							TOTPLT-PRI
- Demand	MontCoFuel	1,562,560	747,527	284,664	6,120	501,833	-	22,415	97%
- Customer	MontCoFuel	51,126	24,458	9,314	200	16,420	-	733	3%
- Commodity	MontCoFuel	-	-	-	-	-	-	-	0%
Total		1,613,685	771,985	293,978	6,320	518,253	-	23,149	
Other Taxes		110							RB-PRI
- Demand	RB-PRI-D	106	65	14	0	25	0	1	97%
- Customer	RB-PRI-C	3	3	0	0	0	0	0	3%
- Commodity	RB-PRI-E	-	-	-	-	-	-	-	0%
Total		110	68	15	0	25	0	1	
Total Taxes Other than Income		5,167,356							
- Demand		5,003,564	2,869,446	801,308	18,916	1,219,795	16,735	77,362	
- Customer		163,793	114,213	24,361	405	22,131	386	2,295	
- Commodity		-	-	-	-	-	-	-	
Total Taxes Other than Income		5,167,356	2,983,660	825,670	19,322	1,241,926	17,122	79,658	
Total Operating Expenses		**16,587,252**							
- Demand		**15,898,080**	**9,595,739**	**2,268,305**	**61,331**	**3,772,837**	**50,241**	**149,625**	
- Customer		**689,172**	**574,125**	**82,535**	**1,026**	**26,650**	**758**	**4,079**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**16,587,252**	**10,169,864**	**2,350,841**	**62,357**	**3,799,487**	**50,999**	**153,704**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
UTILITY PLANT									
Distribution Plant									
(360) Land and Land Rights		8,819,130							360S
- Demand	1NCP-SEC	4,053,968	2,625,285	566,051	15,136	822,033	-	25,463	46%
- Customer	Customers-SEC	4,765,162	4,197,022	522,350	5,426	26,814	-	13,549	54%
- Commodity		-	-	-	-	-	-	-	0%
Total		8,819,130	6,822,307	1,088,401	20,563	848,847	-	39,012	
(361) Structures and Improvements		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(362) Station Equipment		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(362) Station Equipment - Capacitors		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(364) Poles, Towers & Fixtures		89,336,733							364S
- Demand	1NCP-SEC	60,992,685	39,497,891	8,516,347	227,724	12,367,629	-	383,094	68%
- Customer	Customers-SEC	28,344,048	24,964,647	3,107,032	32,278	159,496	-	80,595	32%
- Commodity		-	-	-	-	-	-	-	0%
Total		89,336,733	64,462,538	11,623,379	260,002	12,527,125	-	463,689	
(365) Overhead Conductors & Devices		132,766,709							365S
- Demand	1NCP-SEC	41,103,576	26,618,021	5,739,251	153,466	8,334,668	-	258,171	31%
- Customer	Customers-SEC	91,663,133	80,734,332	10,047,976	104,385	515,801	-	260,639	69%
- Commodity		-	-	-	-	-	-	-	0%
Total		132,766,709	107,352,353	15,787,227	257,850	8,850,469	-	518,810	
(366) Underground Conduit		48,076,058							366S
- Demand	1NCP-SEC	48,076,058	31,133,289	6,712,811	179,498	9,748,494	-	301,965	100%
- Customer	Customers-SEC	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		48,076,058	31,133,289	6,712,811	179,498	9,748,494	-	301,965	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(367) Underground Conductors & Device		217,744,370							367S
- Demand	1NCP-SEC	43,009,147	27,852,039	6,005,324	160,580	8,721,065	-	270,140	20%
- Customer	Customers-SEC	174,735,222	153,901,913	19,154,214	198,986	983,259	-	496,850	80%
- Commodity		-	-	-	-	-	-	-	0%
Total		217,744,370	181,753,951	25,159,538	359,566	9,704,324	-	766,990	
(368) Line Transformers		207,499,128							368S
- Demand	1NCP-SEC	51,148,681	33,123,071	7,141,839	190,970	10,371,537	-	321,264	25%
- Customer	Customers-SEC	156,350,446	137,709,114	17,138,903	178,049	879,806	-	444,574	75%
- Commodity		-	-	-	-	-	-	-	0%
Total		207,499,128	170,832,186	24,280,741	369,020	11,251,343	-	765,838	
(368) Line Transformers - Capacitors		1,518,797							DEM
- Demand	12CP-GEN	1,518,797	928,164	146,877	3,768	327,464	111,621	905	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		1,518,797	928,164	146,877	3,768	327,464	111,621	905	
(369) Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(370, 371) Meters and Installation		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Street Lighting & Signal Systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Distribution Plant		705,760,924							
- Demand		249,902,914	161,777,760	34,828,499	931,142	50,692,890	111,621	1,561,001	
- Customer		455,858,011	401,507,028	49,970,475	519,124	2,565,177	-	1,296,207	
- Commodity		-	-	-	-	-	-	-	
Total		705,760,924	563,284,789	84,798,974	1,450,266	53,258,066	111,621	2,857,209	
General and Intangible Plant									
General Plant		15,100,697							LABOR-SEC
- Demand	LABOR-SEC-D	4,792,553	3,103,581	669,179	17,894	971,797	-	30,102	32%
- Customer	LABOR-SEC-C	10,308,144	9,079,126	1,129,963	11,739	58,005	-	29,311	68%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		15,100,697	12,182,706	1,799,143	29,632	1,029,802	-	59,413	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant		9,451,686							LABOR-SEC
- Demand	LABOR-SEC-D	2,999,710	1,942,564	418,846	11,200	608,258	-	18,841	32%
- Customer	LABOR-SEC-C	6,451,977	5,682,721	707,256	7,347	36,306	-	18,346	68%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		9,451,686	7,625,285	1,126,102	18,547	644,564	-	37,187	
Total General and Intangible Plant		24,552,383							
- Demand		7,792,262	5,046,145	1,088,026	29,093	1,580,055	-	48,943	
- Customer		16,760,120	14,761,847	1,837,219	19,086	94,312	-	47,656	
- Commodity		-	-	-	-	-	-	-	
Total		24,552,383	19,807,992	2,925,245	48,180	1,674,367	-	96,600	
Additions to Utility Plant									
COVID-19 Regulatory Asset Adj excl. Res Adj		4,970,779							DISTPLT-SEC
- Demand	COVID	1,760,103	1,461,003	132,442	2,338	103,945	53,017	7,358	35%
- Customer	COVID	3,210,676	2,665,075	241,593	4,265	189,609	96,711	13,422	65%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		4,970,779	4,126,078	374,036	6,603	293,554	149,728	20,781	
COVID-19 Residential Adjustment		(1,231,608)							DISTPLT-SEC
- Demand	Res-Direct	(436,100)	(436,100)	-	-	-	-	-	35%
- Customer	Res-Direct	(795,508)	(795,508)	-	-	-	-	-	65%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(1,231,608)	(1,231,608)	-	-	-	-	-	
MD Electric Vehicle Program Reg Asset excl. Res Direct		345,271							DISTPLTxRES-SEC
- Demand	DISTPLTxRES-SEC-D	213,559	-	84,402	2,256	122,847	270	3,783	62%
- Customer	DISTPLTxRES-SEC-C	131,712	-	121,096	1,258	6,216	-	3,141	38%
- Commodity	DISTPLTxRES-SEC-E	-	-	-	-	-	-	-	0%
Total		345,271	-	205,498	3,515	129,063	270	6,924	
MD EV Reg Asset - Residential Direct		440,801							DISTPLT-SEC
- Demand	Res-Direct	156,083	156,083	-	-	-	-	-	35%
- Customer	Res-Direct	284,718	284,718	-	-	-	-	-	65%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		440,801	440,801	-	-	-	-	-	
Total Additional to Utility Plant		4,525,243							
- Demand		1,693,646	1,180,986	216,844	4,595	226,792	53,288	11,141	
- Customer		2,831,598	2,154,285	362,690	5,523	195,826	96,711	16,564	
- Commodity		-	-	-	-	-	-	-	
Total		4,525,243	3,335,271	579,534	10,118	422,617	149,999	27,705	
Total Utility Plant		734,838,550							
- Demand		259,388,822	168,004,892	36,133,369	964,830	52,499,736	164,908	1,621,085	
- Customer		475,449,729	418,423,160	52,170,384	543,733	2,855,314	96,711	1,360,427	
- Commodity		-	-	-	-	-	-	-	
Total		**734,838,550**	**586,428,052**	**88,303,753**	**1,508,563**	**55,355,050**	**261,619**	**2,981,513**	
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
Distribution Plant A/D		(270,227,957)							DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(95,685,028)	(61,942,893)	(13,335,443)	(356,524)	(19,409,740)	(42,738)	(597,690)	35%
- Customer	DISTPLT-SEC-C	(174,542,929)	(153,732,547)	(19,133,135)	(198,767)	(982,177)	-	(496,303)	65%
- Commodity	DISTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		(270,227,957)	(215,675,440)	(32,468,578)	(555,291)	(20,391,917)	(42,738)	(1,093,993)	
General Plant A/D		(7,118,998)							LABOR-SEC
- Demand	LABOR-SEC-D	(2,259,377)	(1,463,137)	(315,475)	(8,436)	(458,139)	-	(14,191)	32%
- Customer	LABOR-SEC-C	(4,859,620)	(4,280,218)	(532,704)	(5,534)	(27,346)	-	(13,818)	68%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		(7,118,998)	(5,743,355)	(848,179)	(13,970)	(485,485)	-	(28,009)	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant A/D		(12,714,796)							LABOR-SEC
- Demand	LABOR-SEC-D	(4,035,333)	(2,613,217)	(563,449)	(15,066)	(818,254)	-	(25,346)	32%
- Customer	LABOR-SEC-C	(8,679,464)	(7,644,630)	(951,430)	(9,884)	(48,841)	-	(24,680)	68%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		(12,714,796)	(10,257,847)	(1,514,879)	(24,950)	(867,094)	-	(50,025)	
COVID Reg Asset A/D		(373,917)							COVIDREGASSET-SEC
- Demand	COVIDREGASSET-SEC-D	(132,400)	(102,490)	(13,244)	(234)	(10,394)	(5,302)	(736)	35%
- Customer	COVIDREGASSET-SEC-C	(241,517)	(186,957)	(24,159)	(427)	(18,961)	(9,671)	(1,342)	65%
- Commodity	COVIDREGASSET-SEC-E	-	-	-	-	-	-	-	0%
Total		(373,917)	(289,447)	(37,404)	(660)	(29,355)	(14,973)	(2,078)	
EV Reg Asset A/D		(78,607)							EVREGASSET-SEC
- Demand	EVREGASSET-SEC-D	(36,964)	(15,608)	(8,440)	(226)	(12,285)	(27)	(378)	47%
- Customer	EVREGASSET-SEC-C	(41,643)	(28,472)	(12,110)	(126)	(622)	-	(314)	53%
- Commodity	EVREGASSET-SEC-E	-	-	-	-	-	-	-	0%
Total		(78,607)	(44,080)	(20,550)	(351)	(12,906)	(27)	(692)	
CWIP A/D		(83,734)							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	(29,557)	(19,144)	(4,117)	(110)	(5,982)	(19)	(185)	35%
- Customer	TOTPLT-SEC-C	(54,177)	(47,679)	(5,945)	(62)	(325)	(11)	(155)	65%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		(83,734)	(66,823)	(10,062)	(172)	(6,308)	(30)	(340)	
Total Accumulated Depreciation		(290,598,009)							
- Demand		(102,178,660)	(66,156,490)	(14,240,168)	(380,595)	(20,714,794)	(48,086)	(638,526)	
- Customer		(188,419,350)	(165,920,501)	(20,659,483)	(214,799)	(1,078,272)	(9,682)	(536,612)	
- Commodity		-	-	-	-	-	-	-	
Total Accumulated Depreciation		**(290,598,009)**	**(232,076,991)**	**(34,899,652)**	**(595,395)**	**(21,793,066)**	**(57,768)**	**(1,175,138)**	
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Construction Work in Progress		25,213,142							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	8,899,924	5,764,438	1,239,777	33,104	1,801,325	5,658	55,621	35%
- Customer	TOTPLT-SEC-C	16,313,218	14,356,572	1,790,025	18,656	97,969	3,318	46,678	65%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		25,213,142	20,121,010	3,029,802	51,761	1,899,294	8,976	102,299	
Plant Held for Future Use		-							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	-	-	-	-	-	-	-	35%
- Customer	TOTPLT-SEC-C	-	-	-	-	-	-	-	65%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Prepayments		-							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	-	-	-	-	-	-	-	35%
- Customer	TOTPLT-SEC-C	-	-	-	-	-	-	-	65%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Working Capital		8,193,648							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	2,892,255	1,873,300	402,897	10,758	585,386	1,839	18,076	35%
- Customer	TOTPLT-SEC-C	5,301,392	4,665,531	581,714	6,063	31,838	1,078	15,169	65%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		8,193,648	6,538,831	984,611	16,821	617,224	2,917	33,245	
ADIT		(112,406,627)							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	(39,678,134)	(25,699,336)	(5,527,242)	(147,588)	(8,030,768)	(25,226)	(247,974)	35%
- Customer	TOTPLT-SEC-C	(72,728,493)	(64,005,265)	(7,980,388)	(83,174)	(436,771)	(14,794)	(208,102)	65%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		(112,406,627)	(89,704,601)	(13,507,630)	(230,762)	(8,467,540)	(40,019)	(456,075)	
Customer Advances		(2,606,881)							DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(923,071)	(597,561)	(128,647)	(3,439)	(187,245)	(412)	(5,766)	35%
- Customer	DISTPLT-SEC-C	(1,683,811)	(1,483,054)	(184,577)	(1,917)	(9,475)	-	(4,788)	65%
- Commodity	DISTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		(2,606,881)	(2,080,615)	(313,223)	(5,357)	(196,720)	(412)	(10,554)	
Customer Deposits		(6,991,714)							TOTPLT-SEC
- Demand	Deposits	(2,467,988)	(1,348,432)	(367,601)	-	(744,681)	-	(7,273)	35%
- Customer	Deposits	(4,523,727)	(2,471,625)	(673,799)	-	(1,364,972)	-	(13,331)	65%
- Commodity	Deposits	-	-	-	-	-	-	-	0%
Total		(6,991,714)	(3,820,057)	(1,041,401)	-	(2,109,653)	-	(20,604)	
Deferred Investment Tax Credit		-							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	-	-	-	-	-	-	-	35%
- Customer	TOTPLT-SEC-C	-	-	-	-	-	-	-	65%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Total Other Rate Base Items		(88,598,432)							
- Demand		(31,277,013)	(20,007,592)	(4,380,816)	(107,165)	(6,575,983)	(18,141)	(187,316)	
- Customer		(57,321,419)	(48,937,840)	(6,467,025)	(60,372)	(1,681,411)	(10,397)	(164,374)	
- Commodity		-	-	-	-	-	-	-	
Total		(88,598,432)	(68,945,432)	(10,847,841)	(167,537)	(8,257,394)	(28,538)	(351,690)	
Total Rate Base		**355,642,109**							
- Demand		**125,933,149**	**81,840,810**	**17,512,385**	**477,070**	**25,208,959**	**98,682**	**795,244**	
- Customer		**229,708,960**	**203,564,819**	**25,043,875**	**268,562**	**95,631**	**76,632**	**659,441**	
- Commodity		-	-	-	-	-	-	-	
Total		**355,642,109**	**285,405,628**	**42,556,260**	**745,632**	**25,304,590**	**175,313**	**1,454,685**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
OPERATIONS & MAINTENANCE EXPENSES									

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering		26,791							DistOpExp-SEC
- Demand	DistOpExp-SEC-D	8,839	5,724	1,234	33	1,792	-	56	33%
- Customer	DistOpExp-SEC-C	17,952	15,811	1,968	20	101	-	51	67%
- Commodity	DistOpExp-SEC-E	-	-	-	-	-	-	-	0%
Total		26,791	21,536	3,202	53	1,893	-	107	
(581) Load Dispatching		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(582) Station Expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(583) Overhead line expenses		580,684							OHLines-SEC
- Demand	OHLines-SEC-D	179,775	116,420	25,102	671	36,453	-	1,129	31%
- Customer	OHLines-SEC-C	400,908	353,109	43,947	457	2,256	-	1,140	69%
- Commodity	OHLines-SEC-E	-	-	-	-	-	-	-	0%
Total		580,684	469,528	69,049	1,128	38,709	-	2,269	
(584) Underground line expenses		927,833							UGLines-SEC
- Demand	UGLines-SEC-D	317,928	205,885	44,392	1,187	64,467	-	1,997	34%
- Customer	UGLines-SEC-C	609,904	537,187	66,857	695	3,432	-	1,734	66%
- Commodity	UGLines-SEC-E	-	-	-	-	-	-	-	0%
Total		927,833	743,072	111,249	1,882	67,899	-	3,731	
(585) Street lighting and signal system expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(586) Meter expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(588) Miscellaneous distribution expenses		1,731,421							DistOpExp-SEC
- Demand	DistOpExp-SEC-D	571,246	369,930	79,763	2,133	115,833	-	3,588	33%
- Customer	DistOpExp-SEC-C	1,160,174	1,021,849	127,177	1,321	6,528	-	3,299	67%
- Commodity	DistOpExp-SEC-E	-	-	-	-	-	-	-	0%
Total		1,731,421	1,391,779	206,939	3,454	122,361	-	6,887	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(589) Rents		416,823							DistOpExp-SEC
- Demand	DistOpExp-SEC-D	137,522	89,057	19,202	513	27,886	-	864	33%
- Customer	DistOpExp-SEC-C	279,301	246,000	30,617	318	1,572	-	794	67%
- Commodity	DistOpExp-SEC-E	-	-	-	-	-	-	-	0%
Total		416,823	335,057	49,819	832	29,457	-	1,658	
Total Dist. Operations Expenses		3,683,551							
- Demand		1,215,311	787,016	169,693	4,538	246,431	-	7,633	
- Customer		2,468,240	2,173,957	270,565	2,811	13,889	-	7,018	
- Commodity		-	-	-	-	-	-	-	
Total		3,683,551	2,960,973	440,257	7,348	260,321	-	14,652	
Maintenance Expense									
(590) Maintenance Supervision and Engineering		-							DistMtExp-SEC
- Demand	DistMtExp-SEC-D	-	-	-	-	-	-	-	31%
- Customer	DistMtExp-SEC-C	-	-	-	-	-	-	-	69%
- Commodity	DistMtExp-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(591) Maintenance of Structures		-							DistMtExp-SEC
- Demand	DistMtExp-SEC-D	-	-	-	-	-	-	-	31%
- Customer	DistMtExp-SEC-C	-	-	-	-	-	-	-	69%
- Commodity	DistMtExp-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(592) Maintenance of Station Equipment		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(593) Maintenance of Overhead Lines		8,593,859							OHLines-SEC
- Demand	OHLines-SEC-D	2,660,594	1,722,958	371,496	9,934	539,495	-	16,711	31%
- Customer	OHLines-SEC-C	5,933,265	5,225,854	650,396	6,757	33,387	-	16,871	69%
- Commodity	OHLines-SEC-E	-	-	-	-	-	-	-	0%
Total		8,593,859	6,948,812	1,021,892	16,690	572,882	-	33,582	
(594) Maintenance of underground lines		604,498							UGLines-SEC
- Demand	UGLines-SEC-D	207,135	134,138	28,922	773	42,001	-	1,301	34%
- Customer	UGLines-SEC-C	397,363	349,986	43,558	453	2,236	-	1,130	66%
- Commodity	UGLines-SEC-E	-	-	-	-	-	-	-	0%
Total		604,498	484,124	72,480	1,226	44,237	-	2,431	
(595) Maintenance of line transformers		103,807							368S
- Demand	1NCP-SEC	25,589	16,571	3,573	96	5,189	-	161	25%
- Customer	Customers-SEC	78,219	68,893	8,574	89	440	-	222	75%
- Commodity		-	-	-	-	-	-	-	0%
Total		103,807	85,463	12,147	185	5,629	-	383	
(596) Maintenance of street lighting and signal systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(597) Maintenance of meters		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(598) Maintenance of miscellaneous distribution plant		60,458							DistMtExp-SEC
- Demand	DistMtExp-SEC-D	18,805	12,178	2,626	70	3,813	-	118	31%
- Customer	DistMtExp-SEC-C	41,653	36,687	4,566	47	234	-	118	69%
- Commodity	DistMtExp-SEC-E	-	-	-	-	-	-	-	0%
Total		60,458	48,865	7,192	118	4,047	-	237	
Total Dist. Maintenance Expenses		9,362,622							
- Demand		2,912,123	1,885,844	406,617	10,873	590,498	-	18,291	
- Customer		6,450,499	5,681,420	707,094	7,346	36,298	-	18,342	
- Commodity		-	-	-	-	-	-	-	
Total		9,362,622	7,567,264	1,113,711	18,219	626,796	-	36,633	
Total Distribution Expenses		13,046,172							
- Demand		4,127,434	2,672,860	576,309	15,410	836,929	-	25,924	
- Customer		8,918,739	7,855,377	977,659	10,157	50,187	-	25,360	
- Commodity		-	-	-	-	-	-	-	
Total		13,046,172	10,528,237	1,553,968	25,567	887,116	-	51,284	
Customer Accounts and Services									
Meter Reading & Billing		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Other-Direct to Other		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Uncollectibles		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Misc. Cust Serv and Info Exp		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Rebates & Incentives		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Assistance		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Sales Expense		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
All Other Cust Accts & Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Customer Accounts and Services		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Administrative & General Expense									
Administrative and General Salaries		982,267							NONAGLAB-SEC
- Demand	NONAGLAB-SEC-D	311,745	201,881	43,529	1,164	63,213	-	1,958	32%
- Customer	NONAGLAB-SEC-C	670,522	590,577	73,502	764	3,773	-	1,907	68%
- Commodity	NONAGLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		982,267	792,458	117,030	1,928	66,986	-	3,865	
Outside Services		1,891,211							NONAGLAB-SEC
- Demand	NONAGLAB-SEC-D	600,219	388,692	83,808	2,241	121,708	-	3,770	32%
- Customer	NONAGLAB-SEC-C	1,290,992	1,137,070	141,517	1,470	7,265	-	3,671	68%
- Commodity	NONAGLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		1,891,211	1,525,762	225,325	3,711	128,972	-	7,441	
Employee Benefits (Acct. 926)		(586,284)							NONAGLAB-SEC
- Demand	NONAGLAB-SEC-D	(186,071)	(120,496)	(25,981)	(695)	(37,730)	-	(1,169)	32%
- Customer	NONAGLAB-SEC-C	(400,214)	(352,497)	(43,871)	(456)	(2,252)	-	(1,138)	68%
- Commodity	NONAGLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		(586,284)	(472,993)	(69,852)	(1,150)	(39,982)	-	(2,307)	
Regulatory Commission Expenses (Acct 928)		683,013							DISTPLT-SEC
- Demand	SalesREV	241,848	154,208	44,915	770	30,380	1,888	9,687	35%
- Customer	SalesREV	441,165	281,296	81,931	1,405	55,418	3,444	17,671	65%
- Commodity	SalesREV	-	-	-	-	-	-	-	0%
Total		683,013	435,504	126,845	2,175	85,799	5,332	27,359	
General Advertising Expense		13,317							OpExp-SEC
- Demand	OpExp-SEC-D	4,213	2,728	588	16	854	-	26	32%
- Customer	OpExp-SEC-C	9,104	8,018	998	10	51	-	26	68%
- Commodity	OpExp-SEC-E	-	-	-	-	-	-	-	0%
Total		13,317	10,746	1,586	26	906	-	52	
All Other O&M		533,374							NONAGLAB-SEC
- Demand	NONAGLAB-SEC-D	169,278	109,622	23,636	632	34,325	-	1,063	32%
- Customer	NONAGLAB-SEC-C	364,095	320,685	39,912	415	2,049	-	1,035	68%
- Commodity	NONAGLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		533,374	430,307	63,548	1,047	36,374	-	2,099	
Total A&G Expense		3,516,897							
- Demand		1,141,233	736,635	170,495	4,128	212,751	1,888	15,336	
- Customer		2,375,664	1,985,149	293,988	3,608	66,304	3,444	23,172	
- Commodity		-	-	-	-	-	-	-	
Total		3,516,897	2,721,784	464,482	7,735	279,055	5,332	38,508	
Total O&M Expenses		16,563,069							
- Demand		5,268,666	3,409,495	746,804	19,538	1,049,680	1,888	41,261	
- Customer		11,294,403	9,840,526	1,271,646	13,764	116,491	3,444	48,532	
- Commodity		-	-	-	-	-	-	-	
Total		**16,563,069**	**13,250,021**	**2,018,451**	**33,302**	**1,166,171**	**5,332**	**89,793**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
DEPRECIATION EXPENSE									
Depreciation Expense									
Distribution Plant DeprExp		14,779,284							DISTPLT-SEC
- Demand	DISTPLT-SEC-D	5,233,197	3,387,775	729,341	19,499	1,061,556	2,337	32,689	35%
- Customer	DISTPLT-SEC-C	9,546,087	8,407,927	1,046,428	10,871	53,717	-	27,144	65%
- Commodity	DISTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		14,779,284	11,795,703	1,775,769	30,370	1,115,273	2,337	59,833	
General Plant DeprExp		762,800							LABOR-SEC
- Demand	LABOR-SEC-D	242,092	156,775	33,803	904	49,090	-	1,521	32%
- Customer	LABOR-SEC-C	520,708	458,625	57,079	593	2,930	-	1,481	68%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		762,800	615,400	90,882	1,497	52,020	-	3,001	
Intangible Plant DeprExp		1,121,857							LABOR-SEC
- Demand	LABOR-SEC-D	356,047	230,570	49,714	1,329	72,196	-	2,236	32%
- Customer	LABOR-SEC-C	765,810	674,504	83,947	872	4,309	-	2,178	68%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		1,121,857	905,074	133,661	2,201	76,506	-	4,414	
Total Depreciation Expenses		16,663,941							
- Demand		5,831,336	3,775,121	812,858	21,732	1,182,842	2,337	36,446	
- Customer		10,832,605	9,541,056	1,187,454	12,336	60,957	-	30,802	
- Commodity		-	-	-	-	-	-	-	
Total		**16,663,941**	**13,316,177**	**2,000,312**	**34,068**	**1,243,798**	**2,337**	**67,248**	
Regulatory Debits and Credits									
MD EDIS		(196,192)							DEM
- Demand	1NCP-SEC	(196,192)	(127,051)	(27,394)	(733)	(39,782)	-	(1,232)	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		(196,192)	(127,051)	(27,394)	(733)	(39,782)	-	(1,232)	
MD Electric Vehicle Program		152,181							EVREGASSET-SEC
- Demand	EVREGASSET-SEC-D	71,561	30,217	16,340	437	23,783	52	732	47%
- Customer	EVREGASSET-SEC-C	80,619	55,120	23,444	244	1,203	-	608	53%
- Commodity	EVREGASSET-SEC-E	-	-	-	-	-	-	-	0%
Total		152,181	85,338	39,784	680	24,986	52	1,340	
MD Conservation Voltage Reduction (CVR)		-							DISTPLT-SEC
- Demand	DISTPLT-SEC-D	-	-	-	-	-	-	-	35%
- Customer	DISTPLT-SEC-C	-	-	-	-	-	-	-	65%
- Commodity	DISTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Deferral of Rate Case Expenses		(37,596)							DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(13,312)	(8,618)	(1,855)	(50)	(2,700)	(6)	(83)	35%
- Customer	DISTPLT-SEC-C	(24,283)	(21,388)	(2,662)	(28)	(137)	-	(69)	65%
- Commodity	DISTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		(37,596)	(30,006)	(4,517)	(77)	(2,837)	(6)	(152)	
COVID-19		994,156							DISTPLT-SEC
- Demand	COVID	352,021	292,201	26,488	468	20,789	10,603	1,472	35%
- Customer	COVID	642,135	533,015	48,319	853	37,922	19,342	2,684	65%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		994,156	825,216	74,807	1,321	58,711	29,946	4,156	
COVID-19 - Residential Adjustment		(246,322)							DISTPLT-SEC
- Demand	Res-Direct	(87,220)	(87,220)	-	-	-	-	-	35%
- Customer	Res-Direct	(159,102)	(159,102)	-	-	-	-	-	65%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(246,322)	(246,322)	-	-	-	-	-	
Total Regulatory Debits and Credits		666,228							
- Demand		126,858	99,529	13,579	122	2,089	10,650	889	
- Customer		539,370	407,646	69,101	1,069	38,989	19,342	3,224	
- Commodity		-	-	-	-	-	-	-	
Total		666,228	507,175	82,680	1,191	41,078	29,992	4,112	
Taxes Other than Income									
Distribution Payroll Taxes		194,972							DISTLAB-SEC
- Demand	DISTLAB-SEC-D	61,879	40,072	8,640	231	12,547	-	389	32%
- Customer	DISTLAB-SEC-C	133,093	117,225	14,589	152	749	-	378	68%
- Commodity	DISTLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		194,972	157,296	23,230	383	13,296	-	767	
Customer Account Payroll Taxes		-							CUSTLAB-SEC
- Demand	CUSTLAB-SEC-D	-	-	-	-	-	-	-	0%
- Customer	CUSTLAB-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	CUSTLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
A&G Payroll Taxes		3,296							AGLAB-SEC
- Demand	AGLAB-SEC-D	1,046	677	146	4	212	-	7	32%
- Customer	AGLAB-SEC-C	2,250	1,982	247	3	13	-	6	68%

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
- Commodity	AGLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		3,296	2,659	393	6	225	-	13	
Gross Receipt Taxes		3,467,544							TOTPLT-SEC
- Demand	Revenue	1,224,000	760,705	224,939	3,971	176,538	12,536	45,310	35%
- Customer	Revenue	2,243,544	1,394,343	412,304	7,279	323,588	22,978	83,052	65%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		3,467,544	2,155,048	637,243	11,250	500,127	35,514	128,362	
Property Taxes		6,720,341							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	2,372,196	1,536,460	330,452	8,824	480,127	1,508	14,825	35%
- Customer	TOTPLT-SEC-C	4,348,145	3,826,618	477,115	4,973	26,113	884	12,442	65%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		6,720,341	5,363,078	807,567	13,796	506,240	2,393	27,267	
Sales & Use Tax		(100,946)							TOTPLT-SEC
- Demand	Revenue	(35,633)	(22,145)	(6,548)	(116)	(5,139)	(365)	(1,319)	35%
- Customer	Revenue	(65,313)	(40,591)	(12,003)	(212)	(9,420)	(669)	(2,418)	65%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		(100,946)	(62,737)	(18,551)	(327)	(14,559)	(1,034)	(3,737)	
Montgomery County Fuel Energy		4,741,261							TOTPLT-SEC
- Demand	MontCoFuel	1,673,606	800,651	304,894	6,555	537,497	-	24,008	35%
- Customer	MontCoFuel	3,067,655	1,467,562	558,860	12,015	985,212	-	44,006	65%
- Commodity	MontCoFuel	-	-	-	-	-	-	-	0%
Total		4,741,261	2,268,213	863,754	18,571	1,522,709	-	68,014	
Other Taxes		322							RB-SEC
- Demand	RB-SEC-D	114	74	16	0	23	0	1	35%
- Customer	RB-SEC-C	208	184	23	0	0	0	1	65%
- Commodity	RB-SEC-E	-	-	-	-	-	-	-	0%
Total		322	258	39	1	23	0	1	
Total Taxes Other than Income		15,026,790							
- Demand		5,297,208	3,116,494	862,538	19,470	1,201,806	13,679	83,221	
- Customer		9,729,582	6,767,322	1,451,135	24,209	1,326,254	23,194	137,467	
- Commodity		-	-	-	-	-	-	-	
Total Taxes Other than Income		15,026,790	9,883,816	2,313,674	43,679	2,528,060	36,873	220,688	
Total Operating Expenses		**48,920,028**							
- Demand		**16,524,069**	**10,400,639**	**2,435,780**	**60,863**	**3,436,417**	**28,555**	**161,816**	
- Customer		**32,395,959**	**26,556,550**	**3,979,336**	**51,378**	**1,542,690**	**45,980**	**220,025**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**48,920,028**	**36,957,189**	**6,415,116**	**112,241**	**4,979,107**	**74,534**	**381,841**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
UTILITY PLANT									
Distribution Plant									
(360) Land and Land Rights		-							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer		-	-	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(361) Structures and Improvements		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(362) Station Equipment		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(362) Station Equipment - Capacitors		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(364) Poles, Towers & Fixtures		-							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer		-	-	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(365) Overhead Conductors & Devices		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(366) Underground Conduit		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(367) Underground Conductors & Device		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(368) Line Transformers		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(368) Line Transformers - Capacitors		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(369) Services		73,051,113							369
- Demand	1NCPxLT-SEC	-	-	-	-	-	-	-	0%
- Customer	CUSxLT-SEC	73,051,113	64,524,857	8,030,589	83,427	412,241	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		73,051,113	64,524,857	8,030,589	83,427	412,241	-	-	
(370, 371) Meters and Installation		58,934,191							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Meters	58,934,191	35,003,730	16,591,288	366,058	5,986,423	986,692	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		58,934,191	35,003,730	16,591,288	366,058	5,986,423	986,692	-	
Street Lighting & Signal Systems		33,964,292							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	StreetLighting	33,964,292	-	-	-	-	-	33,964,292	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		33,964,292	-	-	-	-	-	33,964,292	
Total Distribution Plant		165,949,597							
- Demand		-	-	-	-	-	-	-	
- Customer		165,949,597	99,528,588	24,621,876	449,485	6,398,664	986,692	33,964,292	
- Commodity		-	-	-	-	-	-	-	
Total		165,949,597	99,528,588	24,621,876	449,485	6,398,664	986,692	33,964,292	
General and Intangible Plant									
General Plant		23,877,340							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	23,877,340	17,203,736	4,021,648	71,117	864,442	127,413	1,588,984	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		23,877,340	17,203,736	4,021,648	71,117	864,442	127,413	1,588,984	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant		14,945,080							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	14,945,080	10,768,001	2,517,192	44,513	541,063	79,749	994,562	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		14,945,080	10,768,001	2,517,192	44,513	541,063	79,749	994,562	
Total General and Intangible Plant		38,822,420							
- Demand		-	-	-	-	-	-	-	
- Customer		38,822,420	27,971,737	6,538,840	115,629	1,405,506	207,162	2,583,546	
- Commodity		-	-	-	-	-	-	-	
Total		38,822,420	27,971,737	6,538,840	115,629	1,405,506	207,162	2,583,546	
Additions to Utility Plant									
COVID-19 Regulatory Asset Adj excl. Res Adj		1,168,808							DISTPLT-CS
- Demand	COVID	-	-	-	-	-	-	-	0%
- Customer	COVID	1,168,808	970,188	87,949	1,553	69,025	35,206	4,886	100%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		1,168,808	970,188	87,949	1,553	69,025	35,206	4,886	
COVID-19 Residential Adjustment		(289,595)							DISTPLT-CS
- Demand	Res-Direct	-	-	-	-	-	-	-	0%
- Customer	Res-Direct	(289,595)	(289,595)	-	-	-	-	-	100%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(289,595)	(289,595)	-	-	-	-	-	
MD Electric Vehicle Program Reg Asset excl. Res Direct		81,186							DISTPLTxRES-CS
- Demand	DISTPLTxRES-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLTxRES-CS-C	81,186	-	30,095	549	7,821	1,206	41,514	100%
- Commodity	DISTPLTxRES-CS-E	-	-	-	-	-	-	-	0%
Total		81,186	-	30,095	549	7,821	1,206	41,514	
MD EV Reg Asset - Residential Direct		103,648							DISTPLT-CS
- Demand	Res-Direct	-	-	-	-	-	-	-	0%
- Customer	Res-Direct	103,648	103,648	-	-	-	-	-	100%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		103,648	103,648	-	-	-	-	-	
Total Additional to Utility Plant		1,064,046							
- Demand		-	-	-	-	-	-	-	
- Customer		1,064,046	784,241	118,044	2,102	76,846	36,412	46,400	
- Commodity		-	-	-	-	-	-	-	
Total		1,064,046	784,241	118,044	2,102	76,846	36,412	46,400	
Total Utility Plant		205,836,063							
- Demand		-	-	-	-	-	-	-	
- Customer		205,836,063	128,284,566	31,278,760	567,216	7,881,016	1,230,267	36,594,238	
- Commodity		-	-	-	-	-	-	-	
Total		**205,836,063**	**128,284,566**	**31,278,760**	**567,216**	**7,881,016**	**1,230,267**	**36,594,238**	
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
Distribution Plant A/D		(63,540,243)							DISTPLT-CS
- Demand	DISTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLT-CS-C	(63,540,243)	(38,108,382)	(9,427,441)	(172,103)	(2,449,977)	(377,793)	(13,004,547)	100%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		(63,540,243)	(38,108,382)	(9,427,441)	(172,103)	(2,449,977)	(377,793)	(13,004,547)	
General Plant A/D		(11,256,615)							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	(11,256,615)	(8,110,444)	(1,895,946)	(33,527)	(407,528)	(60,067)	(749,103)	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		(11,256,615)	(8,110,444)	(1,895,946)	(33,527)	(407,528)	(60,067)	(749,103)	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant A/D		(2,989,703)							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	(2,989,703)	(2,154,095)	(503,554)	(8,905)	(108,238)	(15,953)	(198,958)	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		(2,989,703)	(2,154,095)	(503,554)	(8,905)	(108,238)	(15,953)	(198,958)	
COVID Reg Asset A/D		(87,921)							COVIDREGASSET-CS
- Demand	COVIDREGASSET-CS-D	-	-	-	-	-	-	-	0%
- Customer	COVIDREGASSET-CS-C	(87,921)	(68,059)	(8,795)	(155)	(6,903)	(3,521)	(489)	100%
- Commodity	COVIDREGASSET-CS-E	-	-	-	-	-	-	-	0%
Total		(87,921)	(68,059)	(8,795)	(155)	(6,903)	(3,521)	(489)	
EV Reg Asset A/D		(18,483)							EVREGASSET-CS
- Demand	EVREGASSET-CS-D	-	-	-	-	-	-	-	0%
- Customer	EVREGASSET-CS-C	(18,483)	(10,365)	(3,009)	(55)	(782)	(121)	(4,151)	100%
- Commodity	EVREGASSET-CS-E	-	-	-	-	-	-	-	0%
Total		(18,483)	(10,365)	(3,009)	(55)	(782)	(121)	(4,151)	
CWIP A/D		(19,689)							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	(19,689)	(12,271)	(2,992)	(54)	(754)	(118)	(3,500)	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		(19,689)	(12,271)	(2,992)	(54)	(754)	(118)	(3,500)	
Total Accumulated Depreciation		(77,912,654)							
- Demand		-	-	-	-	-	-	-	
- Customer		(77,912,654)	(48,463,616)	(11,841,737)	(214,799)	(2,974,181)	(457,573)	(13,960,748)	
- Commodity		-	-	-	-	-	-	-	
Total Accumulated Depreciation		**(77,912,654)**	**(48,463,616)**	**(11,841,737)**	**(214,799)**	**(2,974,181)**	**(457,573)**	**(13,960,748)**	
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Construction Work in Progress		7,062,468							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	7,062,468	4,401,589	1,073,210	19,462	270,407	42,212	1,255,590	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		7,062,468	4,401,589	1,073,210	19,462	270,407	42,212	1,255,590	
Plant Held for Future Use		-							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	-	-	-	-	-	-	-	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Prepayments		-							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	-	-	-	-	-	-	-	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Working Capital		2,295,128							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	2,295,128	1,430,407	348,767	6,325	87,875	13,718	408,036	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		2,295,128	1,430,407	348,767	6,325	87,875	13,718	408,036	
ADIT		(31,486,287)							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	(31,486,287)	(19,623,406)	(4,784,643)	(86,766)	(1,205,542)	(188,191)	(5,597,740)	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		(31,486,287)	(19,623,406)	(4,784,643)	(86,766)	(1,205,542)	(188,191)	(5,597,740)	
Customer Advances		(612,971)							DISTPLT-CS
- Demand	DISTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLT-CS-C	(612,971)	(367,630)	(90,946)	(1,660)	(23,635)	(3,645)	(125,454)	100%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		(612,971)	(367,630)	(90,946)	(1,660)	(23,635)	(3,645)	(125,454)	
Customer Deposits		(1,958,453)							TOTPLT-CS
- Demand	Deposits	-	-	-	-	-	-	-	0%
- Customer	Deposits	(1,958,453)	(1,070,038)	(291,707)	-	(590,936)	-	(5,771)	100%
- Commodity	Deposits	-	-	-	-	-	-	-	0%
Total		(1,958,453)	(1,070,038)	(291,707)	-	(590,936)	-	(5,771)	
Deferred Investment Tax Credit		-							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	-	-	-	-	-	-	-	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Total Other Rate Base Items		(24,700,115)							
- Demand		-	-	-	-	-	-	-	
- Customer		(24,700,115)	(15,229,079)	(3,745,320)	(62,640)	(1,461,831)	(135,906)	(4,065,340)	
- Commodity		-	-	-	-	-	-	-	
Total		(24,700,115)	(15,229,079)	(3,745,320)	(62,640)	(1,461,831)	(135,906)	(4,065,340)	
Total Rate Base		**103,223,294**							
- Demand		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
- Customer		**103,223,294**	**64,591,871**	**15,691,703**	**289,778**	**3,445,004**	**636,788**	**18,568,150**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**103,223,294**	**64,591,871**	**15,691,703**	**289,778**	**3,445,004**	**636,788**	**18,568,150**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
OPERATIONS & MAINTENANCE EXPENSES									
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering		23,160							DistOpExp-CS
- Demand	DistOpExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistOpExp-CS-C	23,160	14,171	5,068	105	1,647	266	1,902	100%
- Commodity	DistOpExp-CS-E	-	-	-	-	-	-	-	0%
Total		23,160	14,171	5,068	105	1,647	266	1,902	
(581) Load Dispatching		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(582) Station Expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(583) Overhead line expenses		226,558							OHLines-CS
- Demand	OHLines-CS-D	-	-	-	-	-	-	-	0%
- Customer	OHLines-CS-C	226,558	200,115	24,906	259	1,279	-	-	100%
- Commodity	OHLines-CS-E	-	-	-	-	-	-	-	0%
Total		226,558	200,115	24,906	259	1,279	-	-	
(584) Underground line expenses		74,177							UGLines-CS
- Demand	UGLines-CS-D	-	-	-	-	-	-	-	0%
- Customer	UGLines-CS-C	74,177	65,519	8,154	85	419	-	-	100%
- Commodity	UGLines-CS-E	-	-	-	-	-	-	-	0%
Total		74,177	65,519	8,154	85	419	-	-	
(585) Street lighting and signal system expenses		107,100							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	StreetLighting	107,100	-	-	-	-	-	107,100	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		107,100	-	-	-	-	-	107,100	
(586) Meter expenses		896,233							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Meters	896,233	532,314	252,310	5,567	91,038	15,005	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		896,233	532,314	252,310	5,567	91,038	15,005	-	
(588) Miscellaneous distribution expenses		1,496,762							DistOpExp-CS
- Demand	DistOpExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistOpExp-CS-C	1,496,762	915,856	327,537	6,784	106,438	17,222	122,926	100%
- Commodity	DistOpExp-CS-E	-	-	-	-	-	-	-	0%
Total		1,496,762	915,856	327,537	6,784	106,438	17,222	122,926	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(589) Rents		360,331							DistOpExp-CS
- Demand	DistOpExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistOpExp-CS-C	360,331	220,483	78,851	1,633	25,624	4,146	29,593	100%
- Commodity	DistOpExp-CS-E	-	-	-	-	-	-	-	0%
Total		360,331	220,483	78,851	1,633	25,624	4,146	29,593	
Total Dist. Operations Expenses		3,184,320							
- Demand		-	-	-	-	-	-	-	
- Customer		3,184,320	1,948,458	696,826	14,432	226,443	36,640	261,521	
- Commodity		-	-	-	-	-	-	-	
Total		3,184,320	1,948,458	696,826	14,432	226,443	36,640	261,521	
Maintenance Expense									
(590) Maintenance Supervision and Engineering		-							DistMtExp-CS
- Demand	DistMtExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistMtExp-CS-C	-	-	-	-	-	-	-	100%
- Commodity	DistMtExp-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(591) Maintenance of Structures		-							DistMtExp-CS
- Demand	DistMtExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistMtExp-CS-C	-	-	-	-	-	-	-	100%
- Commodity	DistMtExp-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(592) Maintenance of Station Equipment		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(593) Maintenance of Overhead Lines		3,352,951							OHLines-CS
- Demand	OHLines-CS-D	-	-	-	-	-	-	-	0%
- Customer	OHLines-CS-C	3,352,951	2,961,607	368,594	3,829	18,921	-	-	100%
- Commodity	OHLines-CS-E	-	-	-	-	-	-	-	0%
Total		3,352,951	2,961,607	368,594	3,829	18,921	-	-	
(594) Maintenance of underground lines		48,327							UGLines-CS
- Demand	UGLines-CS-D	-	-	-	-	-	-	-	0%
- Customer	UGLines-CS-C	48,327	42,687	5,313	55	273	-	-	100%
- Commodity	UGLines-CS-E	-	-	-	-	-	-	-	0%
Total		48,327	42,687	5,313	55	273	-	-	
(595) Maintenance of line transformers		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(596) Maintenance of street lighting and signal systems		465,742							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	StreetLighting	465,742	-	-	-	-	-	465,742	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		465,742	-	-	-	-	-	465,742	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(597) Maintenance of meters		914,278							CUS
- Demand	Meters	-	-	-	-	-	-	-	0%
- Customer		914,278	543,032	257,390	5,679	92,871	15,307	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		914,278	543,032	257,390	5,679	92,871	15,307	-	
(598) Maintenance of miscellaneous distribution plant		31,075							DistMtExp-CS
- Demand	DistMtExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistMtExp-CS-C	31,075	23,055	4,103	62	728	99	3,027	100%
- Commodity	DistMtExp-CS-E	-	-	-	-	-	-	-	0%
Total		31,075	23,055	4,103	62	728	99	3,027	
Total Dist. Maintenance Expenses		4,812,374							
- Demand		-	-	-	-	-	-	-	
- Customer		4,812,374	3,570,381	635,399	9,625	112,793	15,407	468,769	
- Commodity		-	-	-	-	-	-	-	
Total		4,812,374	3,570,381	635,399	9,625	112,793	15,407	468,769	
Total Distribution Expenses		7,996,694							
- Demand		-	-	-	-	-	-	-	
- Customer		7,996,694	5,518,839	1,332,225	24,057	339,236	52,046	730,290	
- Commodity		-	-	-	-	-	-	-	
Total		7,996,694	5,518,839	1,332,225	24,057	339,236	52,046	730,290	
Customer Accounts and Services									
Meter Reading & Billing		6,854,217							CUS
- Demand	MeterReading	-	-	-	-	-	-	-	0%
- Customer		6,854,217	5,857,097	934,546	12,631	44,634	-	5,309	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		6,854,217	5,857,097	934,546	12,631	44,634	-	5,309	
Other-Direct to Other		-							CUS
- Demand	Customers-SEC	-	-	-	-	-	-	-	0%
- Customer		-	-	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Uncollectibles		1,132,614							CUS
- Demand	Uncollectibles	-	-	-	-	-	-	-	0%
- Customer		1,132,614	1,131,744	330	6	259	275	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		1,132,614	1,131,744	330	6	259	275	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Misc. Cust Serv and Info Exp		2,381,813							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	CustServices	2,381,813	2,178,507	182,913	2,013	6,213	-	12,167	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		2,381,813	2,178,507	182,913	2,013	6,213	-	12,167	
Customer Rebates & Incentives		-							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Customers-SEC	-	-	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Customer Assistance		233,396							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	CustAssist	233,396	233,396	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		233,396	233,396	-	-	-	-	-	
Sales Expense		1							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Customers-SEC	1	1	0	0	0	-	0	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		1	1	0	0	0	-	0	
All Other Cust Accts & Services		-							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Customers-SEC	-	-	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Total Customer Accounts and Services		10,602,041							
- Demand		-	-	-	-	-	-	-	
- Customer		10,602,041	9,400,745	1,117,789	14,650	51,106	275	17,476	
- Commodity		-	-	-	-	-	-	-	
Total		10,602,041	9,400,745	1,117,789	14,650	51,106	275	17,476	
Administrative & General Expense									
Administrative and General Salaries		1,553,168							NONAGLAB-CS
- Demand	NONAGLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	NONAGLAB-CS-C	1,553,168	1,119,065	261,599	4,626	56,230	8,288	103,360	100%
- Commodity	NONAGLAB-CS-E	-	-	-	-	-	-	-	0%
Total		1,553,168	1,119,065	261,599	4,626	56,230	8,288	103,360	
Outside Services		2,990,398							NONAGLAB-CS
- Demand	NONAGLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	NONAGLAB-CS-C	2,990,398	2,154,596	503,671	8,907	108,263	15,957	199,004	100%
- Commodity	NONAGLAB-CS-E	-	-	-	-	-	-	-	0%
Total		2,990,398	2,154,596	503,671	8,907	108,263	15,957	199,004	
Employee Benefits (Acct. 926)		(927,037)							NONAGLAB-CS
- Demand	NONAGLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	NONAGLAB-CS-C	(927,037)	(667,935)	(156,140)	(2,761)	(33,562)	(4,947)	(61,692)	100%
- Commodity	NONAGLAB-CS-E	-	-	-	-	-	-	-	0%
Total		(927,037)	(667,935)	(156,140)	(2,761)	(33,562)	(4,947)	(61,692)	
Regulatory Commission Expenses (Acct 928)		160,601							DISTPLT-CS
- Demand	SalesREV	-	-	-	-	-	-	-	0%
- Customer	SalesREV	160,601	102,402	29,826	511	20,174	1,254	6,433	100%
- Commodity	SalesREV	-	-	-	-	-	-	-	0%
Total		160,601	102,402	29,826	511	20,174	1,254	6,433	
General Advertising Expense		18,984							OpExp-CS
- Demand	OpExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	OpExp-CS-C	18,984	15,229	2,501	40	398	53	763	100%
- Commodity	OpExp-CS-E	-	-	-	-	-	-	-	0%
Total		18,984	15,229	2,501	40	398	53	763	
All Other O&M		843,375							NONAGLAB-CS
- Demand	NONAGLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	NONAGLAB-CS-C	843,375	607,655	142,049	2,512	30,533	4,500	56,125	100%
- Commodity	NONAGLAB-CS-E	-	-	-	-	-	-	-	0%
Total		843,375	607,655	142,049	2,512	30,533	4,500	56,125	
Total A&G Expense		4,639,488							
- Demand		-	-	-	-	-	-	-	
- Customer		4,639,488	3,331,013	783,506	13,834	182,037	25,106	303,993	
- Commodity		-	-	-	-	-	-	-	
Total		4,639,488	3,331,013	783,506	13,834	182,037	25,106	303,993	
Total O&M Expenses		23,238,223							
- Demand		-	-	-	-	-	-	-	
- Customer		23,238,223	18,250,596	3,233,520	52,541	572,378	77,427	1,051,760	
- Commodity		-	-	-	-	-	-	-	
Total		**23,238,223**	**18,250,596**	**3,233,520**	**52,541**	**572,378**	**77,427**	**1,051,760**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
DEPRECIATION EXPENSE									
Depreciation Expense									
Distribution Plant DeprExp		3,475,137							DISTPLT-CS
- Demand	DISTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLT-CS-C	3,475,137	2,084,220	515,605	9,413	133,994	20,662	711,244	100%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		3,475,137	2,084,220	515,605	9,413	133,994	20,662	711,244	
General Plant DeprExp		1,206,145							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	1,206,145	869,034	203,150	3,592	43,667	6,436	80,266	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		1,206,145	869,034	203,150	3,592	43,667	6,436	80,266	
Intangible Plant DeprExp		263,789							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	263,789	190,061	44,430	786	9,550	1,408	17,555	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		263,789	190,061	44,430	786	9,550	1,408	17,555	
Total Depreciation Expenses		4,945,072							
- Demand		-	-	-	-	-	-	-	
- Customer		4,945,072	3,143,315	763,185	13,791	187,211	28,506	809,064	
- Commodity		-	-	-	-	-	-	-	
Total		**4,945,072**	**3,143,315**	**763,185**	**13,791**	**187,211**	**28,506**	**809,064**	
Regulatory Debits and Credits									
MD EDIS		(54,955)							DEM
- Demand	1NCP-SEC	(54,955)	(35,588)	(7,673)	(205)	(11,143)	-	(345)	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		(54,955)	(35,588)	(7,673)	(205)	(11,143)	-	(345)	
MD Electric Vehicle Program		42,627							EVREGASSET-CS
- Demand	EVREGASSET-CS-D	-	-	-	-	-	-	-	0%
- Customer	EVREGASSET-CS-C	42,627	23,904	6,941	127	1,804	278	9,574	100%
- Commodity	EVREGASSET-CS-E	-	-	-	-	-	-	-	0%
Total		42,627	23,904	6,941	127	1,804	278	9,574	
MD Conservation Voltage Reduction (CVR)		-							DISTPLT-CS
- Demand	DISTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLT-CS-C	-	-	-	-	-	-	-	100%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Deferral of Rate Case Expenses		(10,531)							DISTPLT-CS
- Demand	DISTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLT-CS-C	(10,531)	(6,316)	(1,562)	(29)	(406)	(63)	(2,155)	100%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		(10,531)	(6,316)	(1,562)	(29)	(406)	(63)	(2,155)	
COVID-19		233,762							DISTPLT-CS
- Demand	COVID	-	-	-	-	-	-	-	0%
- Customer	COVID	233,762	194,038	17,590	311	13,805	7,041	977	100%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		233,762	194,038	17,590	311	13,805	7,041	977	
COVID-19 - Residential Adjustment		(57,919)							DISTPLT-CS
- Demand	Res-Direct	-	-	-	-	-	-	-	0%
- Customer	Res-Direct	(57,919)	(57,919)	-	-	-	-	-	100%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(57,919)	(57,919)	-	-	-	-	-	
Total Regulatory Debits and Credits		152,984							
- Demand		(54,955)	(35,588)	(7,673)	(205)	(11,143)	-	(345)	
- Customer		207,939	153,707	22,968	409	15,203	7,257	8,396	
- Commodity		-	-	-	-	-	-	-	
Total		152,984	118,118	15,295	204	4,059	7,257	8,051	
Taxes Other than Income									
Distribution Payroll Taxes		176,276							DISTLAB-CS
- Demand	DISTLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTLAB-CS-C	176,276	109,245	33,995	676	10,306	1,645	20,409	100%
- Commodity	DISTLAB-CS-E	-	-	-	-	-	-	-	0%
Total		176,276	109,245	33,995	676	10,306	1,645	20,409	
Customer Account Payroll Taxes		228,896							CUSTLAB-CS
- Demand	CUSTLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	CUSTLAB-CS-C	228,896	195,719	31,088	420	1,483	-	186	100%
- Commodity	CUSTLAB-CS-E	-	-	-	-	-	-	-	0%
Total		228,896	195,719	31,088	420	1,483	-	186	
A&G Payroll Taxes		5,212							AGLAB-CS
- Demand	AGLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	AGLAB-CS-C	5,212	3,755	878	16	189	28	347	100%

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
- Commodity	AGLAB-CS-E	-	-	-	-	-	-	-	0%
Total		5,212	3,755	878	16	189	28	347	
Gross Receipt Taxes		971,296							TOTPLT-CS
- Demand	Revenue	-	-	-	-	-	-	-	0%
- Customer	Revenue	971,296	603,652	178,498	3,151	140,091	9,948	35,956	100%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		971,296	603,652	178,498	3,151	140,091	9,948	35,956	
Property Taxes		1,882,439							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	1,882,439	1,173,205	286,055	5,187	72,074	11,251	334,666	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		1,882,439	1,173,205	286,055	5,187	72,074	11,251	334,666	
Sales & Use Tax		(28,276)							TOTPLT-CS
- Demand	Revenue	-	-	-	-	-	-	-	0%
- Customer	Revenue	(28,276)	(17,573)	(5,196)	(92)	(4,078)	(290)	(1,047)	100%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		(28,276)	(17,573)	(5,196)	(92)	(4,078)	(290)	(1,047)	
Montgomery County Fuel Energy		1,328,077							TOTPLT-CS
- Demand	MontCoFuel	-	-	-	-	-	-	-	0%
- Customer	MontCoFuel	1,328,077	635,350	241,947	5,202	426,527	-	19,052	100%
- Commodity	MontCoFuel	-	-	-	-	-	-	-	0%
Total		1,328,077	635,350	241,947	5,202	426,527	-	19,052	
Other Taxes		90							RB-CS
- Demand	RB-CS-D	-	-	-	-	-	-	-	0%
- Customer	RB-CS-C	90	56	14	0	3	1	16	100%
- Commodity	RB-CS-E	-	-	-	-	-	-	-	0%
Total		90	56	14	0	3	1	16	
Total Taxes Other than Income		4,564,010							
- Demand		-	-	-	-	-	-	-	
- Customer		4,564,010	2,703,409	767,279	14,560	646,594	22,583	409,585	
- Commodity		-	-	-	-	-	-	-	
Total Taxes Other than Income		4,564,010	2,703,409	767,279	14,560	646,594	22,583	409,585	
Total Operating Expenses		**32,900,289**							
- Demand		**(54,955)**	**(35,588)**	**(7,673)**	**(205)**	**(11,143)**	**-**	**(345)**	
- Customer		**32,955,244**	**24,251,027**	**4,786,952**	**81,301**	**1,421,386**	**135,773**	**2,278,805**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**32,900,289**	**24,215,439**	**4,779,278**	**81,096**	**1,410,243**	**135,773**	**2,278,460**	

The Potomac Edison Company (Maryland) Allocation Summary	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
Revenue Requirement							
Sub-Transmission							
- Demand	36,236,875	22,682,439	3,824,041	95,950	8,009,588	1,519,392	105,465
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Primary							
- Demand	26,378,552	16,116,243	3,631,138	102,789	6,241,385	76,148	210,849
- Customer	1,033,733	880,706	118,822	1,421	26,882	870	5,033
- Commodity	-	-	-	-	-	-	-
Secondary							
- Demand	27,721,624	17,744,735	3,948,896	102,637	5,657,512	37,321	230,523
- Customer	52,922,704	44,823,714	6,143,192	74,895	1,551,116	52,788	276,999
- Commodity	-	-	-	-	-	-	-
Sub-Transmission							
- Demand	(54,955)	(35,588)	(7,673)	(205)	(11,143)	-	(345)
- Customer	42,097,001	30,047,266	6,142,756	106,675	1,724,916	192,345	3,883,042
- Commodity	-	-	-	-	-	-	-
Total Revenue Requirement							
- Demand	**90,282,094**	**56,507,828**	**11,396,401**	**301,171**	**19,897,341**	**1,632,861**	**546,491**
- Customer	**96,053,439**	**75,751,686**	**12,404,771**	**182,991**	**3,302,914**	**246,003**	**4,165,074**
- Commodity	-	-	-	-	-	-	-
Total Revenue Requirement	**186,335,533**	**132,259,515**	**23,801,172**	**484,162**	**23,200,255**	**1,878,864**	**4,711,565**

The Potomac Edison Company (Maryland) Allocation Summary	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
Rate Base							
Sub-Transmission							
- Demand	137,876,780	87,245,134	13,521,641	358,821	30,286,130	6,381,146	83,908
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Primary							
- Demand	117,927,146	72,662,906	15,773,042	473,452	28,017,505	291,612	708,628
- Customer	3,855,891	3,416,468	419,976	4,512	2,633	1,257	11,045
- Commodity	-	-	-	-	-	-	-
Secondary							
- Demand	125,933,149	81,840,810	17,512,385	477,070	25,208,959	98,682	795,244
- Customer	229,708,960	203,564,819	25,043,875	268,562	95,631	76,632	659,441
- Commodity	-	-	-	-	-	-	-
Sub-Transmission							
- Demand	-	-	-	-	-	-	-
- Customer	103,223,294	64,591,871	15,691,703	289,778	3,445,004	636,788	18,568,150
- Commodity	-	-	-	-	-	-	-
Total Rate Base							
- Demand	**381,737,074**	**241,748,849**	**46,807,068**	**1,309,343**	**83,512,595**	**6,771,440**	**1,587,780**
- Customer	**336,788,145**	**271,573,158**	**41,155,554**	**562,851**	**3,543,268**	**714,677**	**19,238,636**
- Commodity	-	-	-	-	-	-	-
Total Rate Base	**718,525,219**	**513,322,007**	**87,962,622**	**1,872,194**	**87,055,863**	**7,486,116**	**20,826,416**

The Potomac Edison Company (Maryland) Allocation Summary	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
Total Expenses							
Sub-Transmission							
- Demand	23,965,511	14,853,379	2,655,736	64,530	5,341,157	952,493	98,215
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Primary							
- Demand	15,898,080	9,595,739	2,268,305	61,331	3,772,837	50,241	149,625
- Customer	689,172	574,125	82,535	1,026	26,650	758	4,079
- Commodity	-	-	-	-	-	-	-
Secondary							
- Demand	16,524,069	10,400,639	2,435,780	60,863	3,436,417	28,555	161,816
- Customer	32,395,959	26,556,550	3,979,336	51,378	1,542,690	45,980	220,025
- Commodity	-	-	-	-	-	-	-
Sub-Transmission							
- Demand	(54,955)	(35,588)	(7,673)	(205)	(11,143)	-	(345)
- Customer	32,955,244	24,251,027	4,786,952	81,301	1,421,386	135,773	2,278,805
- Commodity	-	-	-	-	-	-	-
Total Expenses							
- Demand	**56,332,704**	**34,814,169**	**7,352,148**	**186,519**	**12,539,268**	**1,031,289**	**409,311**
- Customer	**66,040,375**	**51,381,702**	**8,848,823**	**133,705**	**2,990,726**	**182,511**	**2,502,908**
- Commodity	-	-	-	-	-	-	-
Total Expenses	**122,373,079**	**86,195,871**	**16,200,971**	**320,224**	**15,529,994**	**1,213,800**	**2,912,220**

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
UTILITY PLANT				
Distribution Plant				
(360) Land and Land Rights				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				
(361) Structures and Improvements				
- Demand	12CP-SUB	1NCP-PRI		
- Customer				
- Commodity				
Total				
(362) Station Equipment				
- Demand	12CP-SUB	1NCP-PRI		
- Customer				
- Commodity				
Total				
(362) Station Equipment - Capacitors				
- Demand	12CP-SUB			
- Customer				
- Commodity				
Total				
(364) Poles, Towers & Fixtures				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				
(365) Overhead Conductors & Devices				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				
(366) Underground Conduit				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				
(367) Underground Conductors & Device				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				
(368) Line Transformers				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				

The Potomac Edison Company (Maryland) **Allocation to Customer Classes** **ALLOCATION FACTORS**	**Sub-Transmission**	**Primary**	**Secondary**	**Customer Service**
(368) Line Transformers - Capacitors				
- Demand			12CP-GEN	
- Customer				
- Commodity				
Total				
(369) Services				
- Demand				1NCPxLT-SEC
- Customer				CUSxLT-SEC
- Commodity				
Total				
(370, 371) Meters and Installation				
- Demand				
- Customer				Meters
- Commodity				
Total				
Street Lighting & Signal Systems				
- Demand				
- Customer				StreetLighting
- Commodity				
Total				
General and Intangible Plant				
General Plant				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				
Intangible Plant				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
Additions to Utility Plant				
COVID-19 Regulatory Asset Adj excl. Res Adj				
- Demand	COVID	COVID	COVID	COVID
- Customer	COVID	COVID	COVID	COVID
- Commodity	COVID	COVID	COVID	COVID
Total				
COVID-19 Residential Adjustment				
- Demand	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Customer	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Commodity	Res-Direct	Res-Direct	Res-Direct	Res-Direct
Total				
MD Electric Vehicle Program Reg Asset excl. Res Direct				
- Demand	DISTPLTxRES-SUB-D	DISTPLTxRES-PRI-D	DISTPLTxRES-SEC-D	DISTPLTxRES-CS-D
- Customer	DISTPLTxRES-SUB-C	DISTPLTxRES-PRI-C	DISTPLTxRES-SEC-C	DISTPLTxRES-CS-C
- Commodity	DISTPLTxRES-SUB-E	DISTPLTxRES-PRI-E	DISTPLTxRES-SEC-E	DISTPLTxRES-CS-E
Total				
MD EV Reg Asset - Residential Direct				
- Demand	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Customer	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Commodity	Res-Direct	Res-Direct	Res-Direct	Res-Direct
Total				
ACCUMULATED DEPRECIATION				
Accumulated Depreciation				
Distribution Plant A/D				
- Demand	DISTPLT-SUB-D	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-SUB-C	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-SUB-E	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total				
General Plant A/D				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				
Intangible Plant A/D				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				
COVID Reg Asset A/D				
- Demand	COVIDREGASSET-SUB-D	COVIDREGASSET-PRI-D	COVIDREGASSET-SEC-D	COVIDREGASSET-CS-D
- Customer	COVIDREGASSET-SUB-C	COVIDREGASSET-PRI-C	COVIDREGASSET-SEC-C	COVIDREGASSET-CS-C
- Commodity	COVIDREGASSET-SUB-E	COVIDREGASSET-PRI-E	COVIDREGASSET-SEC-E	COVIDREGASSET-CS-E
Total				
EV Reg Asset A/D				
- Demand	EVREGASSET-SUB-D	EVREGASSET-PRI-D	EVREGASSET-SEC-D	EVREGASSET-CS-D
- Customer	EVREGASSET-SUB-C	EVREGASSET-PRI-C	EVREGASSET-SEC-C	EVREGASSET-CS-C
- Commodity	EVREGASSET-SUB-E	EVREGASSET-PRI-E	EVREGASSET-SEC-E	EVREGASSET-CS-E
Total				

The Potomac Edison Company (Maryland) **Allocation to Customer Classes** **ALLOCATION FACTORS**	**Sub-Transmission**	**Primary**	**Secondary**	**Customer Service**
CWIP A/D				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				

The Potomac Edison Company (Maryland) **Allocation to Customer Classes** **ALLOCATION FACTORS**	**Sub-Transmission**	**Primary**	**Secondary**	**Customer Service**
OTHER RATE BASE ITEMS				
Other Rate Base Items				
Construction Work in Progress				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
Plant Held for Future Use				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
Prepayments				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
Working Capital				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
ADIT				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
Customer Advances				
- Demand	DISTPLT-SUB-D	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-SUB-C	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-SUB-E	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
Customer Deposits				
- Demand	Deposits	Deposits	Deposits	Deposits
- Customer	Deposits	Deposits	Deposits	Deposits
- Commodity	Deposits	Deposits	Deposits	Deposits
Total				
Deferred Investment Tax Credit				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
OPERATIONS & MAINTENANCE EXPENSES				
Distribution Expenses				
Operations Expenses				
(580) Operation Supervision & Engineering				
- Demand	DistOpExp-SUB-D	DistOpExp-PRI-D	DistOpExp-SEC-D	DistOpExp-CS-D
- Customer	DistOpExp-SUB-C	DistOpExp-PRI-C	DistOpExp-SEC-C	DistOpExp-CS-C
- Commodity	DistOpExp-SUB-E	DistOpExp-PRI-E	DistOpExp-SEC-E	DistOpExp-CS-E
Total				
(581) Load Dispatching				
- Demand		1NCP-PRI		
- Customer				
- Commodity				
Total				
(582) Station Expenses				
- Demand		1NCP-PRI		
- Customer				
- Commodity				
Total				
(583) Overhead line expenses				
- Demand	OHLines-SUB-D	OHLines-PRI-D	OHLines-SEC-D	OHLines-CS-D
- Customer	OHLines-SUB-C	OHLines-PRI-C	OHLines-SEC-C	OHLines-CS-C
- Commodity	OHLines-SUB-E	OHLines-PRI-E	OHLines-SEC-E	OHLines-CS-E
Total				
(584) Underground line expenses				
- Demand	UGLines-SUB-D	UGLines-PRI-D	UGLines-SEC-D	UGLines-CS-D
- Customer	UGLines-SUB-C	UGLines-PRI-C	UGLines-SEC-C	UGLines-CS-C
- Commodity	UGLines-SUB-E	UGLines-PRI-E	UGLines-SEC-E	UGLines-CS-E
Total				
(585) Street lighting and signal system expenses				
- Demand				
- Customer				StreetLighting
- Commodity				
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
(586) Meter expenses				
- Demand				
- Customer				Meters
- Commodity				
Total				
(588) Miscellaneous distribution expenses				
- Demand	DistOpExp-SUB-D	DistOpExp-PRI-D	DistOpExp-SEC-D	DistOpExp-CS-D
- Customer	DistOpExp-SUB-C	DistOpExp-PRI-C	DistOpExp-SEC-C	DistOpExp-CS-C
- Commodity	DistOpExp-SUB-E	DistOpExp-PRI-E	DistOpExp-SEC-E	DistOpExp-CS-E
Total				
(589) Rents				
- Demand	DistOpExp-SUB-D	DistOpExp-PRI-D	DistOpExp-SEC-D	DistOpExp-CS-D
- Customer	DistOpExp-SUB-C	DistOpExp-PRI-C	DistOpExp-SEC-C	DistOpExp-CS-C
- Commodity	DistOpExp-SUB-E	DistOpExp-PRI-E	DistOpExp-SEC-E	DistOpExp-CS-E
Total				
Maintenance Expense				
(590) Maintenance Supervision and Engineering				
- Demand	DistMtExp-SUB-D	DistMtExp-PRI-D	DistMtExp-SEC-D	DistMtExp-CS-D
- Customer	DistMtExp-SUB-C	DistMtExp-PRI-C	DistMtExp-SEC-C	DistMtExp-CS-C
- Commodity	DistMtExp-SUB-E	DistMtExp-PRI-E	DistMtExp-SEC-E	DistMtExp-CS-E
Total				
(591) Maintenance of Structures				
- Demand	DistMtExp-SUB-D	DistMtExp-PRI-D	DistMtExp-SEC-D	DistMtExp-CS-D
- Customer	DistMtExp-SUB-C	DistMtExp-PRI-C	DistMtExp-SEC-C	DistMtExp-CS-C
- Commodity	DistMtExp-SUB-E	DistMtExp-PRI-E	DistMtExp-SEC-E	DistMtExp-CS-E
Total				
(592) Maintenance of Station Equipment				
- Demand		1NCP-PRI		
- Customer				
- Commodity				
Total				
(593) Maintenance of Overhead Lines				
- Demand	OHLines-SUB-D	OHLines-PRI-D	OHLines-SEC-D	OHLines-CS-D
- Customer	OHLines-SUB-C	OHLines-PRI-C	OHLines-SEC-C	OHLines-CS-C
- Commodity	OHLines-SUB-E	OHLines-PRI-E	OHLines-SEC-E	OHLines-CS-E
Total				
(594) Maintenance of underground lines				
- Demand	UGLines-SUB-D	UGLines-PRI-D	UGLines-SEC-D	UGLines-CS-D
- Customer	UGLines-SUB-C	UGLines-PRI-C	UGLines-SEC-C	UGLines-CS-C
- Commodity	UGLines-SUB-E	UGLines-PRI-E	UGLines-SEC-E	UGLines-CS-E
Total				
(595) Maintenance of line transformers				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
(596) Maintenance of street lighting and signal systems				
- Demand				
- Customer				StreetLighting
- Commodity				
Total				
(597) Maintenance of meters				
- Demand				
- Customer				Meters
- Commodity				
Total				
(598) Maintenance of miscellaneous distribution plant				
- Demand	DistMtExp-SUB-D	DistMtExp-PRI-D	DistMtExp-SEC-D	DistMtExp-CS-D
- Customer	DistMtExp-SUB-C	DistMtExp-PRI-C	DistMtExp-SEC-C	DistMtExp-CS-C
- Commodity	DistMtExp-SUB-E	DistMtExp-PRI-E	DistMtExp-SEC-E	DistMtExp-CS-E
Total				
Customer Accounts and Services				
Meter Reading & Billing				
- Demand				
- Customer				MeterReading
- Commodity				
Total				
Other-Direct to Other				
- Demand				
- Customer				Customers-SEC
- Commodity				
Total				
Uncollectibles				
- Demand				
- Customer				Uncollectibles
- Commodity				
Total				
Misc. Cust Serv and Info Exp				
- Demand				
- Customer				CustServices
- Commodity				
Total				
Customer Rebates & Incentives				
- Demand				
- Customer				Customers-SEC
- Commodity				
Total				
Customer Assistance				
- Demand				
- Customer				CustAssist
- Commodity				
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
Sales Expense				
- Demand				
- Customer				Customers-SEC
- Commodity				
Total				
All Other Cust Accts & Services				
- Demand				
- Customer				Customers-SEC
- Commodity				
Total				
Administrative & General Expense				
Administrative and General Salaries				
- Demand	NONAGLAB-SUB-D	NONAGLAB-PRI-D	NONAGLAB-SEC-D	NONAGLAB-CS-D
- Customer	NONAGLAB-SUB-C	NONAGLAB-PRI-C	NONAGLAB-SEC-C	NONAGLAB-CS-C
- Commodity	NONAGLAB-SUB-E	NONAGLAB-PRI-E	NONAGLAB-SEC-E	NONAGLAB-CS-E
Total				
Outside Services				
- Demand	NONAGLAB-SUB-D	NONAGLAB-PRI-D	NONAGLAB-SEC-D	NONAGLAB-CS-D
- Customer	NONAGLAB-SUB-C	NONAGLAB-PRI-C	NONAGLAB-SEC-C	NONAGLAB-CS-C
- Commodity	NONAGLAB-SUB-E	NONAGLAB-PRI-E	NONAGLAB-SEC-E	NONAGLAB-CS-E
Total				
Employee Benefits (Acct. 926)				
- Demand	NONAGLAB-SUB-D	NONAGLAB-PRI-D	NONAGLAB-SEC-D	NONAGLAB-CS-D
- Customer	NONAGLAB-SUB-C	NONAGLAB-PRI-C	NONAGLAB-SEC-C	NONAGLAB-CS-C
- Commodity	NONAGLAB-SUB-E	NONAGLAB-PRI-E	NONAGLAB-SEC-E	NONAGLAB-CS-E
Total				
Regulatory Commission Expenses (Acct 928)				
- Demand	SalesREV	SalesREV	SalesREV	SalesREV
- Customer	SalesREV	SalesREV	SalesREV	SalesREV
- Commodity	SalesREV	SalesREV	SalesREV	SalesREV
Total				
General Advertising Expense				
- Demand	OpExp-SUB-D	OpExp-PRI-D	OpExp-SEC-D	OpExp-CS-D
- Customer	OpExp-SUB-C	OpExp-PRI-C	OpExp-SEC-C	OpExp-CS-C
- Commodity	OpExp-SUB-E	OpExp-PRI-E	OpExp-SEC-E	OpExp-CS-E
Total				
All Other O&M				
- Demand	NONAGLAB-SUB-D	NONAGLAB-PRI-D	NONAGLAB-SEC-D	NONAGLAB-CS-D
- Customer	NONAGLAB-SUB-C	NONAGLAB-PRI-C	NONAGLAB-SEC-C	NONAGLAB-CS-C
- Commodity	NONAGLAB-SUB-E	NONAGLAB-PRI-E	NONAGLAB-SEC-E	NONAGLAB-CS-E
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
DEPRECIATION EXPENSE				
Depreciation Expense				
Distribution Plant DeprExp				
- Demand	DISTPLT-SUB-D	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-SUB-C	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-SUB-E	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total				
General Plant DeprExp				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				
Intangible Plant DeprExp				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				
Regulatory Debits and Credits				
MD EDIS				
- Demand	1NCP-PRI	1NCP-PRI	1NCP-SEC	1NCP-SEC
- Customer				
- Commodity				
Total				
MD Electric Vehicle Program				
- Demand	EVREGASSET-SUB-D	EVREGASSET-PRI-D	EVREGASSET-SEC-D	EVREGASSET-CS-D
- Customer	EVREGASSET-SUB-C	EVREGASSET-PRI-C	EVREGASSET-SEC-C	EVREGASSET-CS-C
- Commodity	EVREGASSET-SUB-E	EVREGASSET-PRI-E	EVREGASSET-SEC-E	EVREGASSET-CS-E
Total				
MD Conservation Voltage Reduction (CVR)				
- Demand	DISTPLT-SUB-D	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-SUB-C	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-SUB-E	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total				
Deferral of Rate Case Expenses				
- Demand	DISTPLT-SUB-D	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-SUB-C	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-SUB-E	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total				
COVID-19				
- Demand	COVID	COVID	COVID	COVID
- Customer	COVID	COVID	COVID	COVID
- Commodity	COVID	COVID	COVID	COVID
Total				
COVID-19 - Residential Adjustment				
- Demand	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Customer	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Commodity	Res-Direct	Res-Direct	Res-Direct	Res-Direct
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
TAXES				
Taxes Other than Income				
Distribution Payroll Taxes				
- Demand	DISTLAB-SUB-D	DISTLAB-PRI-D	DISTLAB-SEC-D	DISTLAB-CS-D
- Customer	DISTLAB-SUB-C	DISTLAB-PRI-C	DISTLAB-SEC-C	DISTLAB-CS-C
- Commodity	DISTLAB-SUB-E	DISTLAB-PRI-E	DISTLAB-SEC-E	DISTLAB-CS-E
Total				
Customer Account Payroll Taxes				
- Demand	CUSTLAB-SUB-D	CUSTLAB-PRI-D	CUSTLAB-SEC-D	CUSTLAB-CS-D
- Customer	CUSTLAB-SUB-C	CUSTLAB-PRI-C	CUSTLAB-SEC-C	CUSTLAB-CS-C
- Commodity	CUSTLAB-SUB-E	CUSTLAB-PRI-E	CUSTLAB-SEC-E	CUSTLAB-CS-E
Total				
A&G Payroll Taxes				
- Demand	AGLAB-SUB-D	AGLAB-PRI-D	AGLAB-SEC-D	AGLAB-CS-D
- Customer	AGLAB-SUB-C	AGLAB-PRI-C	AGLAB-SEC-C	AGLAB-CS-C
- Commodity	AGLAB-SUB-E	AGLAB-PRI-E	AGLAB-SEC-E	AGLAB-CS-E
Total				
Gross Receipt Taxes				
- Demand	Revenue	Revenue	Revenue	Revenue
- Customer	Revenue	Revenue	Revenue	Revenue
- Commodity	Revenue	Revenue	Revenue	Revenue
Total				
Property Taxes				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
Sales & Use Tax				
- Demand	Revenue	Revenue	Revenue	Revenue
- Customer	Revenue	Revenue	Revenue	Revenue
- Commodity	Revenue	Revenue	Revenue	Revenue
Total				
Montgomery County Fuel Energy				
- Demand	MontCoFuel	MontCoFuel	MontCoFuel	MontCoFuel
- Customer	MontCoFuel	MontCoFuel	MontCoFuel	MontCoFuel
- Commodity	MontCoFuel	MontCoFuel	MontCoFuel	MontCoFuel
Total				
Other Taxes				
- Demand	RB-SUB-D	RB-PRI-D	RB-SEC-D	RB-CS-D
- Customer	RB-SUB-C	RB-PRI-C	RB-SEC-C	RB-CS-C
- Commodity	RB-SUB-E	RB-PRI-E	RB-SEC-E	RB-CS-E
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes CLASSIFICATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
UTILITY PLANT				
Distribution Plant				
(360) Land and Land Rights	DEM	360P	360S	CUS
(361) Structures and Improvements	DEM	DEM		
(362) Station Equipment	DEM	DEM		
(362) Station Equipment - Capacitors	DEM	DEM		
(364) Poles, Towers & Fixtures	DEM	364P	364S	CUS
(365) Overhead Conductors & Devices	DEM	365P	365S	
(366) Underground Conduit	DEM	366P	366S	
(367) Underground Conductors & Device	DEM	367P	367S	
(368) Line Transformers	DEM	368P	368S	
(368) Line Transformers - Capacitors			DEM	
(369) Services				369
(370, 371) Meters and Installation				CUS
Street Lighting & Signal Systems				CUS
General and Intangible Plant				
General Plant	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
Intangible Plant	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
Additions to Utility Plant				
COVID-19 Regulatory Asset Adj excl. Res Adj	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
COVID-19 Residential Adjustment	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
MD Electric Vehicle Program Reg Asset excl. Res D	DISTPLTxRES-SUB	DISTPLTxRES-PRI	DISTPLTxRES-SEC	DISTPLTxRES-CS
MD EV Reg Asset - Residential Direct	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS

The Potomac Edison Company (Maryland) Allocation to Customer Classes CLASSIFICATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
ACCUMULATED DEPRECIATION				
Accumulated Depreciation				
Distribution Plant A/D	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
General Plant A/D	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
Intangible Plant A/D	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
COVID Reg Asset A/D	COVIDREGASSET-SUB	COVIDREGASSET-PRI	COVIDREGASSET-SEC	COVIDREGASSET-CS
EV Reg Asset A/D	EVREGASSET-SUB	EVREGASSET-PRI	EVREGASSET-SEC	EVREGASSET-CS
CWIP A/D	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
OTHER RATE BASE ITEMS				
Other Rate Base Items				
Construction Work in Progress	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Plant Held for Future Use	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Prepayments	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Working Capital	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
ADIT	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Customer Advances	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Customer Deposits	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Deferred Investment Tax Credit	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
OPERATIONS & MAINTENANCE EXPENSES				
Distribution Expenses				
Operations Expenses				
(580) Operation Supervision & Engineering	DistOpExp-SUB	DistOpExp-PRI	DistOpExp-SEC	DistOpExp-CS
(581) Load Dispatching	DEM	DEM		
(582) Station Expenses	DEM	DEM		
(583) Overhead line expenses	OHLines-SUB	OHLines-PRI	OHLines-SEC	OHLines-CS
(584) Underground line expenses	UGLines-SUB	UGLines-PRI	UGLines-SEC	UGLines-CS
(585) Street lighting and signal system expenses				CUS
(586) Meter expenses				CUS
(588) Miscellaneous distribution expenses	DistOpExp-SUB	DistOpExp-PRI	DistOpExp-SEC	DistOpExp-CS
(589) Rents	DistOpExp-SUB	DistOpExp-PRI	DistOpExp-SEC	DistOpExp-CS
Maintenance Expense				
(590) Maintenance Supervision and Engineering	DistMtExp-SUB	DistMtExp-PRI	DistMtExp-SEC	DistMtExp-CS
(591) Maintenance of Structures	DistMtExp-SUB	DistMtExp-PRI	DistMtExp-SEC	DistMtExp-CS
(592) Maintenance of Station Equipment	DEM	DEM		
(593) Maintenance of Overhead Lines	OHLines-SUB	OHLines-PRI	OHLines-SEC	OHLines-CS
(594) Maintenance of underground lines	UGLines-SUB	UGLines-PRI	UGLines-SEC	UGLines-CS
(595) Maintenance of line transformers	DEM	368P	368S	
(596) Maintenance of street lighting and signal systems				CUS
(597) Maintenance of meters				CUS
(598) Maintenance of miscellaneous distribution p	DistMtExp-SUB	DistMtExp-PRI	DistMtExp-SEC	DistMtExp-CS
Customer Accounts and Services				
Meter Reading & Billing				CUS
Other-Direct to Other				CUS
Uncollectibles				CUS
Misc. Cust Serv and Info Exp				CUS
Customer Rebates & Incentives				CUS
Customer Assistance				CUS
Sales Expense				CUS
All Other Cust Accts & Services				CUS

The Potomac Edison Company (Maryland) Allocation to Customer Classes CLASSIFICATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
Administrative & General Expense				
Administrative and General Salaries	NONAGLAB-SUB	NONAGLAB-PRI	NONAGLAB-SEC	NONAGLAB-CS
Outside Services	NONAGLAB-SUB	NONAGLAB-PRI	NONAGLAB-SEC	NONAGLAB-CS
Employee Benefits (Acct. 926)	NONAGLAB-SUB	NONAGLAB-PRI	NONAGLAB-SEC	NONAGLAB-CS
Regulatory Commission Expenses (Acct 928)	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
General Advertising Expense	OpExp-SUB	OpExp-PRI	OpExp-SEC	OpExp-CS
All Other O&M	NONAGLAB-SUB	NONAGLAB-PRI	NONAGLAB-SEC	NONAGLAB-CS
DEPRECIATION EXPENSE				
Depreciation Expense				
Distribution Plant DeprExp	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
General Plant DeprExp	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
Intangible Plant DeprExp	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
Regulatory Debits and Credits				
MD EDIS	DEM	DEM	DEM	DEM
MD Electric Vehicle Program	EVREGASSET-SUB	EVREGASSET-PRI	EVREGASSET-SEC	EVREGASSET-CS
MD Conservation Voltage Reduction (CVR)	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Deferral of Rate Case Expenses	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
COVID-19	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
COVID-19 - Residential Adjustment	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
TAXES				
Taxes Other than Income				
Distribution Payroll Taxes	DISTLAB-SUB	DISTLAB-PRI	DISTLAB-SEC	DISTLAB-CS
Customer Account Payroll Taxes	CUSTLAB-SUB	CUSTLAB-PRI	CUSTLAB-SEC	CUSTLAB-CS
A&G Payroll Taxes	AGLAB-SUB	AGLAB-PRI	AGLAB-SEC	AGLAB-CS
Gross Receipt Taxes	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Property Taxes	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Sales & Use Tax	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Montgomery County Fuel Energy	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Other Taxes	RB-SUB	RB-PRI	RB-SEC	RB-CS
Income Taxes				
State				
Federal				
Income Taxes Deferred - Net				
Allowance for Funds Used During Construction	CWIP-SUB	CWIP-PRI	CWIP-SEC	CWIP-CS
Interest on Customer Deposits	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS

The Potomac Edison Company (Maryland) Summary of Allocators	Description	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
External Allocators								
12CP-GEN	Demand at Generation Level (ACP)	100.00%	61.11%	9.67%	0.25%	21.56%	7.35%	0.06%
12CP-SUB	Demand for Subtransmission (ACP)	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
1NCP-GEN	Demand at Generation Level (NCP)	100.00%	55.41%	12.35%	0.36%	22.64%	8.70%	0.54%
1NCP-PRI	Demand at Primary Level (NCP)	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
1NCP-SEC	Demand at Secondary Level (NCP)	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
1NCPxLT-SEC	Demand at Sec Level w/o St Ltg (NCP)	100.00%	65.17%	14.05%	0.38%	20.41%	0.00%	0.00%
Customers	Average Number of Customers	100.00%	88.04%	10.97%	0.11%	0.59%	0.00%	0.28%
Customers-PRI	Number of Customers at Primary Level	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
Customers-SEC	Number of Customers at Secondary Level	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
Revenue	Revenue from Sales (Distr)	100.00%	62.15%	18.38%	0.32%	14.42%	1.02%	3.70%
LatePayment	Late Payment Charges	100.00%	65.45%	17.55%	0.20%	15.14%	1.66%	0.00%
CUSxLT-SEC	Number of Secondary Cust Excl St. Lighting	100.00%	88.33%	10.99%	0.11%	0.56%	0.00%	0.00%
Meters	Meters	100.00%	59.39%	28.15%	0.62%	10.16%	1.67%	0.00%
StreetLighting	Direct to Street & Area Lighting	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Deposits	Customer Deposits	100.00%	54.64%	14.89%	0.00%	30.17%	0.00%	0.29%
SalesREV	Revenue from Sales	100.00%	63.76%	18.57%	0.32%	12.56%	0.78%	4.01%
MontCoFuel	Montgomery Co. Fuel Tax	100.00%	47.84%	18.22%	0.39%	32.12%	0.00%	1.43%
MeterReading	Acct. 902-903 Meter Reading	100.00%	85.45%	13.63%	0.18%	0.65%	0.00%	0.08%
Uncollectibles	Acct. 904 Uncollectibles	100.00%	99.92%	0.03%	0.00%	0.02%	0.02%	0.00%
CustServices	Misc. Cust Serv and Info Exp	100.00%	91.46%	7.68%	0.08%	0.26%	0.00%	0.51%
COVID	Covid Allocation	100.00%	83.01%	7.52%	0.13%	5.91%	3.01%	0.42%
Res-Direct	Residential Direct Allocation	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CustAssist	Acct. 908 Customer Assistance	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Internal Allocators								
TOTPLT-SUB-D		100.00%	63.07%	9.90%	0.26%	22.16%	4.54%	0.06%
TOTPLT-SUB-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-SUB-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-PRI-D		100.00%	61.44%	13.41%	0.39%	23.93%	0.23%	0.60%
TOTPLT-PRI-C		100.00%	87.99%	10.97%	0.11%	0.62%	0.02%	0.29%
TOTPLT-PRI-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-SEC-D		100.00%	64.77%	13.93%	0.37%	20.24%	0.06%	0.62%
TOTPLT-SEC-C		100.00%	88.01%	10.97%	0.11%	0.60%	0.02%	0.29%
TOTPLT-SEC-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-CS-D		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-CS-C		100.00%	62.32%	15.20%	0.28%	3.83%	0.60%	17.78%
TOTPLT-CS-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-SUB-D		100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
DISTPLT-SUB-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-SUB-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-PRI-D		100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
DISTPLT-PRI-C		100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
DISTPLT-PRI-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-SEC-D		100.00%	64.74%	13.94%	0.37%	20.29%	0.04%	0.62%
DISTPLT-SEC-C		100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
DISTPLT-SEC-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-CS-D		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-CS-C		100.00%	59.98%	14.84%	0.27%	3.86%	0.59%	20.47%
DISTPLT-CS-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-SUB-D		100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
GENPLT-SUB-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-SUB-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-PRI-D		100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
GENPLT-PRI-C		100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
GENPLT-PRI-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-SEC-D		100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
GENPLT-SEC-C		100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
GENPLT-SEC-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-CS-D		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-CS-C		100.00%	72.05%	16.84%	0.30%	3.62%	0.53%	6.65%
GENPLT-CS-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-SUB-D		100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
INTPLT-SUB-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-SUB-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

The Potomac Edison Company (Maryland) Summary of Allocators Description	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
INTPLT-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
INTPLT-PRI-C	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
INTPLT-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
INTPLT-SEC-C	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
INTPLT-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-CS-C	100.00%	72.05%	16.84%	0.30%	3.62%	0.53%	6.65%
INTPLT-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-SUB-D	100.00%	63.10%	10.93%	0.26%	21.09%	4.10%	0.53%
A&G-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-PRI-D	100.00%	61.65%	14.03%	0.39%	22.67%	0.28%	0.99%
A&G-PRI-C	100.00%	85.28%	11.83%	0.14%	1.95%	0.09%	0.71%
A&G-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-SEC-D	100.00%	64.55%	14.94%	0.36%	18.64%	0.17%	1.34%
A&G-SEC-C	100.00%	83.56%	12.37%	0.15%	2.79%	0.14%	0.98%
A&G-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-CS-C	100.00%	71.80%	16.89%	0.30%	3.92%	0.54%	6.55%
A&G-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-SUB-D	100.00%	63.28%	9.81%	0.26%	21.97%	4.63%	0.06%
RB-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-PRI-D	100.00%	61.62%	13.38%	0.40%	23.76%	0.25%	0.60%
RB-PRI-C	100.00%	88.60%	10.89%	0.12%	0.07%	0.03%	0.29%
RB-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-SEC-D	100.00%	64.99%	13.91%	0.38%	20.02%	0.08%	0.63%
RB-SEC-C	100.00%	88.62%	10.90%	0.12%	0.04%	0.03%	0.29%
RB-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-CS-C	100.00%	62.57%	15.20%	0.28%	3.34%	0.62%	17.99%
RB-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-SUB-D	100.00%	63.07%	9.90%	0.26%	22.16%	4.54%	0.06%
CWIP-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-PRI-D	100.00%	61.44%	13.41%	0.39%	23.93%	0.23%	0.60%
CWIP-PRI-C	100.00%	87.99%	10.97%	0.11%	0.62%	0.02%	0.29%
CWIP-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-SEC-D	100.00%	64.77%	13.93%	0.37%	20.24%	0.06%	0.62%
CWIP-SEC-C	100.00%	88.01%	10.97%	0.11%	0.60%	0.02%	0.29%
CWIP-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-CS-C	100.00%	62.32%	15.20%	0.28%	3.83%	0.60%	17.78%
CWIP-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
LABOR-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
LABOR-PRI-C	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
LABOR-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
LABOR-SEC-C	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
LABOR-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-CS-C	100.00%	72.05%	16.84%	0.30%	3.62%	0.53%	6.65%
LABOR-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
DISTLAB-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

The Potomac Edison Company (Maryland) Summary of Allocators Description	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
DISTLAB-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
DISTLAB-PRI-C	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
DISTLAB-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
DISTLAB-SEC-C	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
DISTLAB-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-CS-C	100.00%	61.97%	19.29%	0.38%	5.85%	0.93%	11.58%
DISTLAB-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SUB-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-PRI-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SEC-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-CS-C	100.00%	85.51%	13.58%	0.18%	0.65%	0.00%	0.08%
CUSTLAB-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
AGLAB-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
AGLAB-PRI-C	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
AGLAB-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
AGLAB-SEC-C	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
AGLAB-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-CS-C	100.00%	72.05%	16.84%	0.30%	3.62%	0.53%	6.65%
AGLAB-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
NONAGLAB-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
NONAGLAB-PRI-C	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
NONAGLAB-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
NONAGLAB-SEC-C	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
NONAGLAB-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-CS-C	100.00%	72.05%	16.84%	0.30%	3.62%	0.53%	6.65%
NONAGLAB-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-SUB-D	100.00%	63.28%	9.81%	0.26%	21.97%	4.63%	0.06%
RATEBASE-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-PRI-D	100.00%	61.62%	13.38%	0.40%	23.76%	0.25%	0.60%
RATEBASE-PRI-C	100.00%	88.60%	10.89%	0.12%	0.07%	0.03%	0.29%
RATEBASE-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-SEC-D	100.00%	64.99%	13.91%	0.38%	20.02%	0.08%	0.63%
RATEBASE-SEC-C	100.00%	88.62%	10.90%	0.12%	0.04%	0.03%	0.29%
RATEBASE-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-CS-C	100.00%	62.57%	15.20%	0.28%	3.34%	0.62%	17.99%
RATEBASE-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
DistOpExp-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
DistOpExp-PRI-C	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
DistOpExp-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
DistOpExp-SEC-C	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
DistOpExp-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

The Potomac Edison Company (Maryland) Summary of Allocators Description	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
DistOpExp-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-CS-C	100.00%	61.19%	21.88%	0.45%	7.11%	1.15%	8.21%
DistOpExp-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
OHLines-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
OHLines-PRI-C	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
OHLines-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
OHLines-SEC-C	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
OHLines-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-CS-C	100.00%	88.33%	10.99%	0.11%	0.56%	0.00%	0.00%
OHLines-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
UGLines-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
UGLines-PRI-C	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
UGLines-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
UGLines-SEC-C	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
UGLines-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-CS-C	100.00%	88.33%	10.99%	0.11%	0.56%	0.00%	0.00%
UGLines-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
DistMtExp-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
DistMtExp-PRI-C	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
DistMtExp-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
DistMtExp-SEC-C	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
DistMtExp-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-CS-C	100.00%	74.19%	13.20%	0.20%	2.34%	0.32%	9.74%
DistMtExp-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
OpExp-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
OpExp-PRI-C	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
OpExp-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
OpExp-SEC-C	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
OpExp-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-CS-C	100.00%	80.22%	13.17%	0.21%	2.10%	0.28%	4.02%
OpExp-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-SUB-D	100.00%	0.00%	26.77%	0.69%	60.10%	12.28%	0.17%
DISTPLTxRES-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-PRI-D	100.00%	0.00%	34.76%	1.02%	62.13%	0.55%	1.54%
DISTPLTxRES-PRI-C	100.00%	0.00%	91.75%	0.96%	4.92%	0.00%	2.38%
DISTPLTxRES-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-SEC-D	100.00%	0.00%	39.52%	1.06%	57.52%	0.13%	1.77%
DISTPLTxRES-SEC-C	100.00%	0.00%	91.94%	0.96%	4.72%	0.00%	2.38%
DISTPLTxRES-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-CS-C	100.00%	0.00%	37.07%	0.68%	9.63%	1.49%	51.13%
DISTPLTxRES-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

The Potomac Edison Company (Maryland) Summary of Classifiers Classifier Description	Classifier Code	Total	- Demand	- Customer	- Commodity
External Classifiers					
Common					
Customer Factor	CUS	100.00%	0.00%	100.00%	0.00%
Demand Factor	DEM	100.00%	100.00%	0.00%	0.00%
Commodity Factor	COM	100.00%	0.00%	0.00%	100.00%
360 Primary Classifier	360P	100.00%	98.50%	1.50%	0.00%
360 Secondary Classifier	360S	100.00%	45.97%	54.03%	0.00%
364 Primary Classifier	364P	100.00%	72.95%	27.05%	0.00%
364 Secondary Classifier	364S	100.00%	68.27%	31.73%	0.00%
365 Primary Classifier	365P	100.00%	56.64%	43.36%	0.00%
365 Secondary Classifier	365S	100.00%	30.96%	69.04%	0.00%
366 Primary Classifier	366P	100.00%	100.00%	0.00%	0.00%
366 Secondary Classifier	366S	100.00%	100.00%	0.00%	0.00%
367 Primary Classifier	367P	100.00%	50.08%	49.92%	0.00%
367 Secondary Classifier	367S	100.00%	19.75%	80.25%	0.00%
368 Primary Classifier	368P	100.00%	70.21%	29.79%	0.00%
368 Secondary Classifier	368S	100.00%	24.65%	75.35%	0.00%
369 Classifier	369	100.00%	0.00%	100.00%	0.00%
Internal Classifiers - Derivation and Supporting Data					
TOTPLT					
Total Plant Subtransmission	TOTPLT-SUB	100.00%	100.00%	0.00%	0.00%
Total Plant Primary	TOTPLT-PRI	100.00%	96.83%	3.17%	0.00%
Total Plant Secondary	TOTPLT-SEC	100.00%	35.30%	64.70%	0.00%
Total Plant Customer	TOTPLT-CS	100.00%	0.00%	100.00%	0.00%
DISTPLT					
Dist. Plant Subtransmission	DISTPLT-SUB	100.00%	100.00%	0.00%	0.00%
Dist. Plant Primary	DISTPLT-PRI	100.00%	96.83%	3.17%	0.00%
Dist. Plant Secondary	DISTPLT-SEC	100.00%	35.41%	64.59%	0.00%
Dist. Plant Customer	DISTPLT-CS	100.00%	0.00%	100.00%	0.00%
GENPLT					
General Plant Subtransmission	GENPLT-SUB	100.00%	100.00%	0.00%	0.00%
General Plant Primary	GENPLT-PRI	100.00%	96.77%	3.23%	0.00%
General Plant Secondary	GENPLT-SEC	100.00%	31.74%	68.26%	0.00%
General Plant Customer	GENPLT-CS	100.00%	0.00%	100.00%	0.00%
INTPLT					
Intangible Plant Subtransmission	INTPLT-SUB	100.00%	100.00%	0.00%	0.00%
Intangible Plant Primary	INTPLT-PRI	100.00%	96.77%	3.23%	0.00%
Intangible Plant Secondary	INTPLT-SEC	100.00%	31.74%	68.26%	0.00%
Intangible Plant Customer	INTPLT-CS	100.00%	0.00%	100.00%	0.00%

The Potomac Edison Company (Maryland) Summary of Classifiers Classifier Description	Classifier Code	Total	- Demand	- Customer	- Commodity
A&G					
A&G Subtransmission	A&G-SUB	100.00%	100.00%	0.00%	0.00%
A&G Primary	A&G-PRI	100.00%	96.77%	3.23%	0.00%
A&G Secondary	A&G-SEC	100.00%	32.45%	67.55%	0.00%
A&G Customer	A&G-CS	100.00%	0.00%	100.00%	0.00%
RB					
Rate Base Subtransmission	RB-SUB	100.00%	100.00%	0.00%	0.00%
Rate Base Primary	RB-PRI	100.00%	96.83%	3.17%	0.00%
Rate Base Secondary	RB-SEC	100.00%	35.41%	64.59%	0.00%
Rate Base Customer	RB-CS	100.00%	0.00%	100.00%	0.00%
CWIP					
CWIP Subtransmission	CWIP-SUB	100.00%	100.00%	0.00%	0.00%
CWIP Primary	CWIP-PRI	100.00%	96.83%	3.17%	0.00%
CWIP Secondary	CWIP-SEC	100.00%	35.30%	64.70%	0.00%
CWIP Customer	CWIP-CS	100.00%	0.00%	100.00%	0.00%
LABOR					
LABOR Subtransmission	LABOR-SUB	100.00%	100.00%	0.00%	0.00%
LABOR Primary	LABOR-PRI	100.00%	96.77%	3.23%	0.00%
LABOR Secondary	LABOR-SEC	100.00%	31.74%	68.26%	0.00%
LABOR Customer	LABOR-CS	100.00%	0.00%	100.00%	0.00%
Dist Labor					
Dist Labor Subtransmission	DISTLAB-SUB	100.00%	100.00%	0.00%	0.00%
Dist Labor Primary	DISTLAB-PRI	100.00%	96.77%	3.23%	0.00%
Dist Labor Secondary	DISTLAB-SEC	100.00%	31.74%	68.26%	0.00%
Dist Labor Customer	DISTLAB-CS	100.00%	0.00%	100.00%	0.00%
Cust Labor					
Cust Labor Subtransmission	CUSTLAB-SUB	0.00%	0.00%	0.00%	0.00%
Cust Labor Primary	CUSTLAB-PRI	0.00%	0.00%	0.00%	0.00%
Cust Labor Secondary	CUSTLAB-SEC	0.00%	0.00%	0.00%	0.00%
Cust Labor Customer	CUSTLAB-CS	100.00%	0.00%	100.00%	0.00%
A&G Labor					
A&G Labor Subtransmission	AGLAB-SUB	100.00%	100.00%	0.00%	0.00%
A&G Labor Primary	AGLAB-PRI	100.00%	96.77%	3.23%	0.00%
A&G Labor Secondary	AGLAB-SEC	100.00%	31.74%	68.26%	0.00%
A&G Labor Customer	AGLAB-CS	100.00%	0.00%	100.00%	0.00%
Dist+Cust Labor					
Dist+Cust Labor Subtransmission	NONAGLAB-SUB	100.00%	100.00%	0.00%	0.00%
Dist+Cust Labor Primary	NONAGLAB-PRI	100.00%	96.77%	3.23%	0.00%
Dist+Cust Labor Secondary	NONAGLAB-SEC	100.00%	31.74%	68.26%	0.00%
Dist+Cust Labor Customer	NONAGLAB-CS	100.00%	0.00%	100.00%	0.00%
Rate Base					

The Potomac Edison Company (Maryland)
Summary of Classifiers

Classifier Description	Classifier Code	Total	- Demand	- Customer	- Commodity
Rate Base Subtransmission	RATEBASE-SUB	100.00%	100.00%	0.00%	0.00%
Rate Base Primary	RATEBASE-PRI	100.00%	96.83%	3.17%	0.00%
Rate Base Secondary	RATEBASE-SEC	100.00%	35.41%	64.59%	0.00%
Rate Base Customer	RATEBASE-CS	100.00%	0.00%	100.00%	0.00%
DistOpExp					
DistOpExp Subtransmission	DistOpExp-SUB	100.00%	100.00%	0.00%	0.00%
DistOpExp Primary	DistOpExp-PRI	100.00%	88.18%	11.82%	0.00%
DistOpExp Secondary	DistOpExp-SEC	100.00%	32.99%	67.01%	0.00%
DistOpExp Customer	DistOpExp-CS	100.00%	0.00%	100.00%	0.00%
Overhead Lines					
Overhead Lines Subtransmission	OHLines-SUB	100.00%	100.00%	0.00%	0.00%
Overhead Lines Primary	OHLines-PRI	100.00%	56.64%	43.36%	0.00%
Overhead Lines Secondary	OHLines-SEC	100.00%	30.96%	69.04%	0.00%
Overhead Lines Customer	OHLines-CS	100.00%	0.00%	100.00%	0.00%
U/G Lines					
U/G Lines Subtransmission	UGLines-SUB	100.00%	100.00%	0.00%	0.00%
U/G Lines Primary	UGLines-PRI	100.00%	67.35%	32.65%	0.00%
U/G Lines Secondary	UGLines-SEC	100.00%	34.27%	65.73%	0.00%
U/G Lines Customer	UGLines-CS	100.00%	0.00%	100.00%	0.00%
DistMtExp					
DistMtExp Subtransmission	DistMtExp-SUB	100.00%	100.00%	0.00%	0.00%
DistMtExp Primary	DistMtExp-PRI	100.00%	92.92%	7.08%	0.00%
DistMtExp Secondary	DistMtExp-SEC	100.00%	31.10%	68.90%	0.00%
DistMtExp Customer	DistMtExp-CS	100.00%	0.00%	100.00%	0.00%
Operating Expenses					
Operating Expenses Subtransmission	OpExp-SUB	100.00%	100.00%	0.00%	0.00%
Operating Expenses Primary	OpExp-PRI	100.00%	92.29%	7.71%	0.00%
Operating Expenses Secondary	OpExp-SEC	100.00%	31.64%	68.36%	0.00%
Operating Expenses Customer	OpExp-CS	100.00%	0.00%	100.00%	0.00%
Dist. Plant excl. Residential					
Dist. Plant excl. Res Subtransmission	DISTPLTxRES-SUB	100.00%	100.00%	0.00%	0.00%
Dist. Plant excl. Res Primary	DISTPLTxRES-PRI	100.00%	99.00%	1.00%	0.00%
Dist. Plant excl. Res Secondary	DISTPLTxRES-SEC	100.00%	61.85%	38.15%	0.00%
Dist. Plant excl. Res Customer	DISTPLTxRES-CS	100.00%	0.00%	100.00%	0.00%

The Potomac Edison Company (Maryland) Functional Factors	Code	Total	Sub-Transmission	Primary	Secondary	Customer Service
EXTERNAL FUNCTIONAL FACTORS						
Customer Service Only	CUSTSERVICE	100.0%	0.0%	0.0%	0.0%	100.0%
Primary Distribution Only	PRIMARY	100.0%	0.0%	100.0%	0.0%	0.0%
Secondary Distribution Only	SECONDARY	100.0%	0.0%	0.0%	100.0%	0.0%
Subtransmission Only	SUBTRANSMISSION	100.0%	100.0%	0.0%	0.0%	0.0%
Account 360 Land and Land Rights	ACC360	100.0%	6.9%	54.5%	38.6%	0.0%
Account 361 Structures and Improvements	ACC361	100.0%	0.1%	99.9%	0.0%	0.0%
Account 362 Station Equipment	ACC362	100.0%	0.5%	99.5%	0.0%	0.0%
Account 364 Poles, Towers & Fixtures	ACC364	100.0%	29.5%	4.0%	66.6%	0.0%
Account 365 Overhead Conductors & Devices	ACC365	100.0%	42.8%	3.0%	54.2%	0.0%
Account 366 Underground Conduit	ACC366	100.0%	27.8%	3.7%	68.6%	0.0%
Account 367 Underground Conductors & Device	ACC367	100.0%	30.3%	1.5%	68.2%	0.0%
Account 368 Transformers	ACC368	100.0%	0.0%	0.2%	99.8%	0.0%
INTERNAL FUNCTIONAL FACTORS						
Rate Base Factor	RB	100.0%	19.2%	16.9%	49.5%	14.4%
Total Distribution Plant Factor	DISTPLT	100.0%	19.3%	17.1%	51.5%	12.1%
Total Utility Plant Factor	TOTPLT	100.0%	19.2%	17.0%	49.9%	14.0%
Total General Plant Factor	GENPLT	100.0%	17.5%	15.7%	25.9%	40.9%
Overhead and Service Lines Factor	OHLINES	100.0%	35.3%	2.5%	44.7%	17.4%
Underground Lines Factor	UG LINES	100.0%	28.3%	1.8%	64.7%	5.2%
Distribution Operating Expenses Factor	DISTOPEXP	100.0%	22.4%	5.0%	39.0%	33.7%
Distribution Maintenance Expenses Factor	DISTMTEXP	100.0%	29.2%	12.6%	38.5%	19.8%
Labor Expenses	LABOR	100.0%	17.5%	15.7%	25.9%	40.9%
Dist Labor Expenses	DISTLAB	100.0%	21.2%	19.1%	31.4%	28.4%
Customer Labor Expenses	CUSTLAB	100.0%	0.0%	0.0%	0.0%	100.0%
A&G Labor Expenses	AGLAB	100.0%	17.5%	15.7%	25.9%	40.9%
Non-A&G Labor Expenses	NONAGLAB	100.0%	17.5%	15.7%	25.9%	40.9%
Total Operating Expenses excl. A&G Factor	OPEXP	100.0%	20.8%	7.9%	29.4%	41.9%
INTERNAL FUNCTIONAL FACTORS DERIVATION						
Total Distribution Plant		1,370,353,215	264,958,327	233,684,367	705,760,924	165,949,597
Total Distribution Plant Factor	DISTPLT	100.0%	19.3%	17.1%	51.5%	12.1%
Total General Plant		94,864,996	16,571,017	14,919,176	24,552,383	38,822,420
Total General Plant Factor	GENPLT	100.0%	17.5%	15.7%	25.9%	40.9%
Total Utility Plant		1,474,004,730	283,228,221	250,101,895	734,838,550	205,836,063
Total Utility Plant Factor	TOTPLT	100.0%	19.2%	17.0%	49.9%	14.0%
Overhead and Service Lines (Accts. 365, 369OH)		296,947,998	104,904,585	7,476,890	132,766,709	51,799,814
Overhead and Service Lines Factor	OHLINES	100.0%	35.3%	2.5%	44.7%	17.4%
Underground Lines (Acct. 366-367, 369UG)		410,866,051	116,371,686	7,422,638	265,820,427	21,251,299
Underground Lines Factor	UG LINES	100.0%	28.3%	1.8%	64.7%	5.2%
Distribution Operating Expenses		3,869,177	865,012	191,581	1,508,516	1,304,067
Distribution Operating Expenses Factor	DISTOPEXP	100.0%	22.4%	5.0%	39.0%	33.7%
Distribution Maintenance Expenses		24,178,759	7,055,010	3,040,287	9,302,164	4,781,299
Distribution Maintenance Expenses Factor	DISTMTEXP	100.0%	29.2%	12.6%	38.5%	19.8%
Total Operating Expenses excl. A&G		44,385,845	9,213,081	3,527,856	13,046,172	18,598,735
Total Operating Expenses excl. A&G Factor	OPEXP	100.0%	20.8%	7.9%	29.4%	41.9%

The Potomac Edison Company (Maryland) Functional Factors	Code	Total	Sub-Transmission	Primary	Secondary	Customer Service
Revenue Requirement						
Total Rate Base		718,525,219	137,876,780	121,783,036	355,642,109	103,223,294
Required Return on Rate Base		7.54%	7.54%	7.54%	7.54%	7.54%
Required Net Income		54,188,230	10,398,102	9,184,378	26,821,072	7,784,678
O&M Expenses		56,655,385	11,382,575	5,471,518	16,563,069	23,238,223
Depreciation & Amortization		33,822,024	6,484,474	5,728,537	16,663,941	4,945,072
Regulatory Debits and Credits		1,288,352	249,300	219,841	666,228	152,984
Taxes Other than Income		30,607,318	5,849,161	5,167,356	15,026,790	4,564,010
Total Expenses		122,373,079	23,965,511	16,587,252	48,920,028	32,900,289
Allowance for Funds Used During Construction		2,609,343	501,382	442,740	1,300,841	364,379
Interest on Customer Deposits		(17,180)	(3,301)	(2,915)	(8,565)	(2,399)
Income Taxes		10,884,154	2,088,545	1,844,758	5,387,234	1,563,617
Revenue Requirement		190,037,627	36,950,239	28,056,213	82,420,611	42,610,564

The Potomac Edison Company (Maryland) Target Revenues		Total Company		Residential Service R		Small C & I Schedule C&G		Small C & I Schedule CA-CSH		Medium Power Schedule PH		Large Power Schedule PP		Street and Area Lighting ST LTNG
Revenue Requirements at EROR														
Delivery Revenues at EROR		167,686,930		122,365,061		20,761,563		419,160		18,309,580		1,390,045		4,441,521
Current Delivery Revenues		120,194,282		76,638,469		22,321,797		382,670		15,098,581		938,268		4,814,496
Increase / (Decrease) ($)		47,492,648		45,726,592		(1,560,234)		36,490		3,210,998		451,777		(372,975)
Increase / (Decrease) (%)		39.5%		59.7%		-7.0%		9.5%		21.3%		48.2%		-7.7%
Revenue Requirements at Uniform %														
Uniform Increase in Revenues		167,686,930		106,920,807		31,141,861		533,875		21,064,519		1,309,009		6,716,859
Current Retail Revenues		120,194,282		76,638,469		22,321,797		382,670		15,098,581		938,268		4,814,496
Increase		47,492,648		30,282,338		8,820,064		151,205		5,965,938		370,740		1,902,363
Increase (%)		39.5%		39.5%		39.5%		39.5%		39.5%		39.5%		39.5%
Movement to EROR		**20.00%**												
Revenue Targets														
Step 1: 20% Movement to EROR (excl. Lighting)		161,425,139	$	110,009,658	$	29,065,801	$	510,932	$	20,513,531	$	1,325,216		
Step 2: Set Lighting at 2x Total Increase		5,688,019											$	5,688,019
Step 3: Lighting Adjustment Assigned to Non-Res		573,772			$	324,361	$	5,702	$	228,921	$	14,789		
Adjusted Revenue Targets		167,686,930	$	110,009,658	$	29,390,162	$	516,634	$	20,742,452	$	1,340,005	$	5,688,019
Current Retail Revenues		120,194,282		76,638,469		22,321,797		382,670		15,098,581		938,268		4,814,496
Increase		47,492,648		33,371,189		7,068,365		133,964		5,643,871		401,736		873,523
Increase (%)		39.5%		43.5%		31.7%		35.0%		37.4%		42.8%		18.1%

The Potomac Edison Company (Maryland)
Customer Charge Analysis
Test Period 12 Months Ended December 2022

Plant-In-Service: CCOS

Account Number	Description	Total	Schedule R	Schedules G, C, C-A & CSH	Schedule PH	Schedule PP
369	Services	$ 73,051,113	$ 64,524,857	$ 8,114,015	$ 412,241	$ -
370, 371	Meters and Installation	$ 58,934,191	$ 35,003,730	$ 16,957,346	$ 5,986,423	$ 986,692
	Total		$ 99,528,588	$ 25,071,361	$ 6,398,664	$ 986,692

O&M: Separation Study

Account Number	Description	Total	Schedule R	Schedules G, C, C-A & CSH	Schedule PH	Schedule PP
586	Meter	$ 896,233	$ 532,314	$ 257,876	$ 91,038	$ 15,005
588	Misc. Distribution (Customer-related)	$ 2,682,919	$ 1,960,582	$ 465,698	$ 113,119	$ 17,222
597	Maintenance of Meters	$ 914,278	$ 543,032	$ 263,069	$ 92,871	$ 15,307
902, 903	Meter Reading & Billing	$ 6,854,217	$ 5,857,097	$ 947,177	$ 44,634	$ -
905, 907, 910	Misc. Cust Serv and Info Exp	$ 2,381,813	$ 2,178,507	$ 184,926	$ 6,213	$ -
908	Customer Assistance	$ 233,396	$ 233,396	$ -	$ -	$ -
	Total	**$ 13,962,857**	**$ 11,304,928**	**$ 2,118,746**	**$ 347,874**	**$ 47,534**

Customer Charge

	Schedule R	Schedules G, C, C-A & CSH	Schedule PH	Schedule PP
Plant Accounts Carrying Charge	$ 11,756,223	$ 2,961,406	$ 755,804	$ 116,547
Plus: Related Expenses	$ 11,304,928	$ 2,118,746	$ 347,874	$ 47,534
Total	$ 23,061,151	$ 5,080,151	$ 1,103,678	$ 164,081
Divided by: Customer Count (Annual)	3,007,098	377,906	20,167	121
Total Monthly Customer Charge	$ 7.67	$ 13.44	$ 54.73	$ 1,356.05
Total Monthly Customer Charge (rounded)	$ 8.00	$ 13.00	$ 50.00	$ 1,360.00

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Test Period 12 Months Ended December 2022

Line No.		Current Billing Determinants	Current Rate	Current Revenue	Weather Norm Adjustment	Pro Forma Norm Billing Determinants	Pro Forma Rate	Pro Forma Revenue	Revenue Change	Percent Change
	SCHEDULE R (Residential Service)	*[a]*	*[b]*	*[c]=[a]x[b]*	*[d]*	*[e]=[a]+[d]*	*[f]*	*[g]=[e]x[f]*	*[h]=[g]-[c]*	*[i]=[h]/[c]*
1	Distribution									
2	Fixed Distribution Charge	3,007,098	$ 5.70	$ 17,140,459		3,007,098	$ 8.00	$ 24,056,784	$ 6,916,325	40.35%
3	Energy Charge (kWh)									
4	All kWh	3,349,359,320	$ 0.01750	$ 58,613,788	5,511,280	3,354,870,600	$ 0.02524	$ 84,682,402	$ 26,068,614	44.48%
5	Unbilled	51,597,560		$ 919,208		51,597,560		$ 1,319,450	$ 400,242	43.54%
6	Franchise Tax Surcharge			$ 2,108,602				$ 2,108,602	$ -	0.00%
7	Montgomery County Energy Tax			$ 4,686,975				$ 4,686,975	$ -	0.00%
8	TOTAL SCHEDULE R			$ 83,469,032				$ 116,854,214	$ 33,385,182	40.00%
9	Per Books Revenue			$ 83,434,046				$ 116,805,235	$ 33,371,189	40.00%
10	Correction Factor			1.00042				1.00042		

Total Target	$ 116,805,235
Total Adj. Target	$ 116,854,214
Base Adj. Target	$ 110,058,637
Base Current	$ 76,673,455

The Potomac Edison Company (Maryland)
Typical Bill Comparison

Schedule R								
Energy kWh		Distribution Current Bill		Distribution Proposed Bill		Distribution Incr/(Decr)	Distribution % Change	Total Bill* % Change
100	$	7.54	$	10.52	$	2.98	40%	19.5%
200	$	9.37	$	13.05	$	3.68	39%	15.0%
300	$	11.21	$	15.57	$	4.36	39%	12.9%
400	$	13.04	$	18.10	$	5.06	39%	11.8%
500	$	14.88	$	20.62	$	5.74	39%	11.0%
600	$	16.72	$	23.14	$	6.42	38%	10.5%
700	$	18.55	$	25.67	$	7.12	38%	10.1%
800	$	20.39	$	28.19	$	7.80	38%	9.8%
900	$	22.22	$	30.72	$	8.50	38%	9.5%
1,000	$	24.06	$	33.24	$	9.18	38%	9.3%
1,100	$	25.90	$	35.76	$	9.86	38%	9.2%
1,200	$	27.73	$	38.29	$	10.56	38%	9.0%
1,300	$	29.57	$	40.81	$	11.24	38%	8.9%
1,400	$	31.40	$	43.34	$	11.94	38%	8.8%
1,500	$	33.24	$	45.86	$	12.62	38%	8.7%
1,600	$	35.08	$	48.38	$	13.30	38%	8.7%
1,700	$	36.91	$	50.91	$	14.00	38%	8.6%
1,800	$	38.75	$	53.43	$	14.68	38%	8.5%
1,900	$	40.58	$	55.96	$	15.38	38%	8.5%
2,000	$	42.42	$	58.48	$	16.06	38%	8.4%
2,100	$	44.26	$	61.00	$	16.74	38%	8.4%
2,200	$	46.09	$	63.53	$	17.44	38%	8.3%
2,300	$	47.93	$	66.05	$	18.12	38%	8.3%
2,400	$	49.76	$	68.58	$	18.82	38%	8.3%
2,500	$	51.60	$	71.10	$	19.50	38%	8.2%
2,600	$	53.44	$	73.62	$	20.18	38%	8.2%
2,700	$	55.27	$	76.15	$	20.88	38%	8.2%
2,800	$	57.11	$	78.67	$	21.56	38%	8.2%
2,900	$	58.94	$	81.20	$	22.26	38%	8.1%
3,000	$	60.78	$	83.72	$	22.94	38%	8.1%
3,100	$	62.62	$	86.24	$	23.62	38%	8.1%
3,200	$	64.45	$	88.77	$	24.32	38%	8.1%
3,300	$	66.29	$	91.29	$	25.00	38%	8.0%
3,400	$	68.12	$	93.82	$	25.70	38%	8.0%
3,500	$	69.96	$	96.34	$	26.38	38%	8.0%
3,600	$	71.80	$	98.86	$	27.06	38%	8.0%
3,700	$	73.63	$	101.39	$	27.76	38%	8.0%
3,800	$	75.47	$	103.91	$	28.44	38%	8.0%
3,900	$	77.30	$	106.44	$	29.14	38%	8.0%
4,000	$	79.14	$	108.96	$	29.82	38%	7.9%

*Includes Distribution, Surcharges and SOS (Transmission & Generation) as of March 2023

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Test Period 12 Months Ended December 2022

Line No.	SCHEDULE G (General Service)	Current: Billing Determinants [a]	Current: Rate [b]	Current: Revenue [c]=[a]x[b]	Weather Norm Adjustment [d]	Pro Forma: Norm Billing Determinants [e]=[a]+[d]	Pro Forma: Rate [f]	Pro Forma: Revenue [g]=[e]x[f]	Revenue Change [h]=[g]-[c]	Percent Change [i]=[h]/[c]
1	Distribution									
2	Fixed Distribution Charge	323,003	$ 4.00	$ 1,292,011		323,003	$ 8.00	$ 2,584,022	$ 1,292,011	100.00%
3	Minimum kW	115,326	$ 1.42	$ 163,763		115,326	$ 1.80	$ 207,728	$ 43,965	26.85%
4	kWh in Minimum	1,972,506	$ -	$ -	508	1,973,013	$ -	$ -	$ -	
5	Capacity Charge (kW)									
6	1st Block (0-7.5)	39,591	$ -	$ -		39,591	$ -	$ -	$ -	
7	2nd Block (over 7.5)	1,692,148	$ 1.77	$ 2,995,102		1,692,148	$ 2.25	$ 3,799,188	$ 804,086	26.85%
8	Energy Charge (kWh)									
9	All kWh	821,069,347	$ 0.01869	$ 15,345,786	211,299	821,280,646	$ 0.02371	$ 19,470,632	$ 4,124,846	26.88%
10	Voltage Discount (kW)									
11	2 kV to 15 kV	30,557	$ (0.25)	$ (7,639)		30,557	$ (0.25)	$ (7,639)	$ -	0.00%
12	Over 15 kV	41,599	$ (0.50)	$ (20,799)		41,599	$ (0.50)	$ (20,799)	$ -	0.00%
13	Reactive kVA Charge (kVAR)									
14	Billing kVAR	149,460	$ 0.40	$ 59,784		149,460	$ 0.40	$ 59,784	$ -	0.00%
15	Unbilled	2,654,290		$ 53,290		2,654,290		$ 70,221	$ 16,932	31.77%
16	Franchise Tax Surcharge			$ 511,921				$ 511,921	$ -	0.00%
17	Montgomery County Energy Tax			$ 1,618,759				$ 1,618,759	$ -	0.00%
18	TOTAL SCHEDULE G			$ 22,011,979				$ 28,293,818	$ 6,281,839	28.54%
19	Per Books Revenue			$ 22,058,743				$ 28,334,098	$ 6,275,355	28.45%
20	Correction Factor			0.99858				0.99858		

31.60%

Total Target	$ 28,369,114	
Total Adj. Target	$ 28,328,784	
Base Adj. Target	$ 26,198,103	$ 26,163,137
Base Current	$ 19,881,298	

The Potomac Edison Company (Maryland)
Typical Bill Comparison

Schedule G							
Demand kW	Energy kWh	Load Factor	Distribution Current Bill	Distribution Proposed Bill	Distribution Incr/(Decr)	Distribution % Change	Total Bill* % Change
5.0	730	20%	$ 14.28	$ 25.31	$ 11.03	77%	10.0%
5.0	1,095	30%	$ 21.42	$ 33.96	$ 12.54	59%	8.8%
5.0	1,460	40%	$ 28.56	$ 42.62	$ 14.06	49%	8.1%
5.0	1,825	50%	$ 35.70	$ 51.27	$ 15.57	44%	7.6%
5.0	2,190	60%	$ 42.84	$ 59.92	$ 17.08	40%	7.3%
5.0	2,555	70%	$ 49.98	$ 68.58	$ 18.60	37%	7.0%
5.0	2,920	80%	$ 57.12	$ 77.23	$ 20.11	35%	6.8%
7.5	1,095	20%	$ 21.42	$ 33.96	$ 12.54	59%	8.8%
7.5	1,643	30%	$ 32.14	$ 46.96	$ 14.82	46%	7.9%
7.5	2,190	40%	$ 42.84	$ 59.92	$ 17.08	40%	7.3%
7.5	2,738	50%	$ 53.56	$ 72.92	$ 19.36	36%	6.9%
7.5	3,285	60%	$ 64.25	$ 85.89	$ 21.64	34%	6.6%
7.5	3,833	70%	$ 74.97	$ 98.88	$ 23.91	32%	6.4%
7.5	4,380	80%	$ 85.67	$ 111.85	$ 26.18	31%	6.2%
10.0	1,460	20%	$ 32.98	$ 48.24	$ 15.26	46%	7.6%
10.0	2,190	30%	$ 47.26	$ 65.55	$ 18.29	39%	6.9%
10.0	2,920	40%	$ 61.54	$ 82.86	$ 21.32	35%	6.5%
10.0	3,650	50%	$ 75.82	$ 100.17	$ 24.35	32%	6.3%
10.0	4,380	60%	$ 90.10	$ 117.47	$ 27.37	30%	6.1%
10.0	5,110	70%	$ 104.38	$ 134.78	$ 30.40	29%	5.9%
10.0	5,840	80%	$ 118.66	$ 152.09	$ 33.43	28%	5.8%
20.0	2,920	20%	$ 79.24	$ 105.36	$ 26.12	33%	5.9%
20.0	4,380	30%	$ 107.80	$ 139.97	$ 32.17	30%	5.7%
20.0	5,840	40%	$ 136.36	$ 174.59	$ 38.23	28%	5.5%
20.0	7,300	50%	$ 164.91	$ 209.21	$ 44.30	27%	5.4%
20.0	8,760	60%	$ 193.47	$ 243.82	$ 50.35	26%	5.4%
20.0	10,220	70%	$ 222.03	$ 278.44	$ 56.41	25%	5.3%
20.0	11,680	80%	$ 250.59	$ 313.06	$ 62.47	25%	5.3%
30.0	4,380	20%	$ 125.50	$ 162.47	$ 36.97	29%	5.4%
30.0	6,570	30%	$ 168.33	$ 214.40	$ 46.07	27%	5.3%
30.0	8,760	40%	$ 211.17	$ 266.32	$ 55.15	26%	5.2%
30.0	10,950	50%	$ 254.01	$ 318.25	$ 64.24	25%	5.2%
30.0	13,140	60%	$ 296.84	$ 370.17	$ 73.33	25%	5.1%
30.0	15,330	70%	$ 339.68	$ 422.10	$ 82.42	24%	5.1%
30.0	17,520	80%	$ 382.52	$ 474.02	$ 91.50	24%	5.1%
40.0	5,840	20%	$ 171.76	$ 219.59	$ 47.83	28%	5.2%
40.0	8,760	30%	$ 228.87	$ 288.82	$ 59.95	26%	5.1%
40.0	11,680	40%	$ 285.99	$ 358.06	$ 72.07	25%	5.1%
40.0	14,600	50%	$ 343.10	$ 427.29	$ 84.19	25%	5.1%
40.0	17,520	60%	$ 400.22	$ 496.52	$ 96.30	24%	5.0%
40.0	20,440	70%	$ 457.33	$ 565.76	$ 108.43	24%	5.0%
40.0	23,360	80%	$ 514.45	$ 634.99	$ 120.54	23%	5.0%
50.0	7,300	20%	$ 218.01	$ 276.71	$ 58.70	27%	5.1%
50.0	10,950	30%	$ 289.41	$ 363.25	$ 73.84	26%	5.0%
50.0	14,600	40%	$ 360.80	$ 449.79	$ 88.99	25%	5.0%
50.0	18,250	50%	$ 432.20	$ 536.33	$ 104.13	24%	5.0%
50.0	21,900	60%	$ 503.59	$ 622.87	$ 119.28	24%	5.0%
50.0	25,550	70%	$ 574.98	$ 709.42	$ 134.44	23%	5.0%
50.0	29,200	80%	$ 646.38	$ 795.96	$ 149.58	23%	4.9%

*Includes Distribution, Surcharges and SOS (Transmission & Generation) as of March 2023

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Test Period 12 Months Ended December 2022

Line No.		Current Billing Determinants	Current Rate	Current Revenue	Weather Norm Adjustment	Pro Forma Norm Billing Determinants	Pro Forma Rate	Pro Forma Revenue	Revenue Change	Percent Change
	SCHEDULE C (General Service)	[a]	[b]	[c]=[a]x[b]	[d]	[e]=[a]+[d]	[f]	[g]=[e]x[f]	[h]=[g]-[c]	[i]=[h]/[c]
1	Distribution									
2	Fixed Distribution Charge	50,981	$ 4.00	$ 203,925		50,981	$ 8.00	$ 407,849	$ 203,925	100.00%
3	Minimum kW	39,424	$ 1.42	$ 55,982		39,424	$ 1.80	$ 71,011	$ 15,029	26.85%
4	kWh in Minimum	631,392	$ -	$ -	162	631,554	$ -	$ -	$ -	
5	Energy Charge (kWh)									
6	1st Block (0-350)	10,671,412	$ 0.01869	$ 199,449	2,732	10,674,144	$ 0.02371	$ 253,059	$ 53,610	26.88%
7	2nd Block (351-700)*	32,678,578	$ 0.03540	$ 1,156,822	8,367	32,686,945	$ 0.04489	$ 1,467,273	$ 310,451	26.84%
8	3rd Block (over 700)	39,924,554	$ 0.01869	$ 746,190	10,222	39,934,775	$ 0.02371	$ 946,760	$ 200,570	26.88%
9	Voltage Discount (kW)									
10	2 kV to 15 kV	47,021	$ (0.25)	$ (11,755)		47,021	$ (0.25)	$ (11,755)	$ -	0.00%
11	Reactive kVA Charge (kVAR)									
12	Billing kVAR	32,363	$ 0.40	$ 12,945		32,363	$ 0.40	$ 12,945	$ -	0.00%
13	Unbilled	(55,627)		$ (1,267)		(55,627)		$ (1,668)	$ (401)	31.68%
14	Franchise Tax Surcharge			$ 51,983				$ 51,983	$ -	0.00%
15	Montgomery County Energy Tax			$ 166,079				$ 166,079	$ -	0.00%
16	TOTAL SCHEDULE C			$ 2,580,352				$ 3,363,535	$ 783,184	30.35%
17	Per Books Revenue			$ 2,590,310				$ 3,376,516	$ 786,206	30.35%
18	Correction Factor			0.99616				0.99616		

19 *2nd energy block increases by 53 kWh for each one-half kW in excess of 7.5 kW, with the 3rd energy block including all kWh in excess of the 1st and 2nd energy blocks as adjusted

33.15%

Total Target	$	3,341,500
Total Adj. Target	$	3,328,654
Base Adj. Target	$	3,110,592
Base Current	$	2,362,290

The Potomac Edison Company (Maryland)
Typical Bill Comparison

Schedule C							
Demand kW	Energy kWh	Load Factor	Distribution Current Bill	Distribution Proposed Bill	Distribution Incr/(Decr)	Distribution % Change	Total Bill* % Change
5.0	730	20%	$ 20.13	$ 32.72	$ 12.59	63%	9%
5.0	1,095	30%	$ 27.27	$ 41.38	$ 14.11	52%	9%
5.0	1,460	40%	$ 34.41	$ 50.03	$ 15.62	45%	8%
5.0	1,825	50%	$ 41.55	$ 58.68	$ 17.13	41%	8%
5.0	2,190	60%	$ 48.68	$ 67.34	$ 18.66	38%	7%
5.0	2,555	70%	$ 55.82	$ 75.99	$ 20.17	36%	7%
5.0	2,920	80%	$ 62.96	$ 84.65	$ 21.69	34%	7%
7.5	1,095	20%	$ 27.27	$ 41.38	$ 14.11	52%	9%
7.5	1,643	30%	$ 37.99	$ 54.37	$ 16.38	43%	8%
7.5	2,190	40%	$ 48.68	$ 67.34	$ 18.66	38%	7%
7.5	2,738	50%	$ 59.40	$ 80.33	$ 20.93	35%	7%
7.5	3,285	60%	$ 70.10	$ 93.30	$ 23.20	33%	7%
7.5	3,833	70%	$ 80.82	$ 106.29	$ 25.47	32%	6%
7.5	4,380	80%	$ 91.52	$ 119.26	$ 27.74	30%	6%
10.0	1,460	20%	$ 38.83	$ 55.64	$ 16.81	43%	7%
10.0	2,190	30%	$ 53.11	$ 72.95	$ 19.84	37%	7%
10.0	2,920	40%	$ 67.39	$ 90.26	$ 22.87	34%	7%
10.0	3,650	50%	$ 81.67	$ 107.57	$ 25.90	32%	6%
10.0	4,380	60%	$ 95.95	$ 124.88	$ 28.93	30%	6%
10.0	5,110	70%	$ 110.23	$ 142.18	$ 31.95	29%	6%
10.0	5,840	80%	$ 124.51	$ 159.49	$ 34.98	28%	6%
20.0	2,920	20%	$ 85.10	$ 112.71	$ 27.61	32%	6%
20.0	4,380	30%	$ 113.66	$ 147.33	$ 33.67	30%	6%
20.0	5,840	40%	$ 142.22	$ 181.94	$ 39.72	28%	6%
20.0	7,300	50%	$ 170.78	$ 216.56	$ 45.78	27%	5%
20.0	8,760	60%	$ 199.33	$ 251.18	$ 51.85	26%	5%
20.0	10,220	70%	$ 227.89	$ 285.79	$ 57.90	25%	5%
20.0	11,680	80%	$ 256.45	$ 320.41	$ 63.96	25%	5%
30.0	4,380	20%	$ 131.37	$ 169.78	$ 38.41	29%	5%
30.0	6,570	30%	$ 174.21	$ 221.70	$ 47.49	27%	5%
30.0	8,760	40%	$ 217.05	$ 273.63	$ 56.58	26%	5%
30.0	10,950	50%	$ 259.88	$ 325.55	$ 65.67	25%	5%
30.0	13,140	60%	$ 302.72	$ 377.48	$ 74.76	25%	5%
30.0	15,330	70%	$ 345.56	$ 429.40	$ 83.84	24%	5%
30.0	17,520	80%	$ 388.39	$ 481.33	$ 92.94	24%	5%
40.0	5,840	20%	$ 177.64	$ 226.84	$ 49.20	28%	5%
40.0	8,760	30%	$ 234.76	$ 296.08	$ 61.32	26%	5%
40.0	11,680	40%	$ 291.88	$ 365.31	$ 73.43	25%	5%
40.0	14,600	50%	$ 348.99	$ 434.54	$ 85.55	25%	5%
40.0	17,520	60%	$ 406.11	$ 503.78	$ 97.67	24%	5%
40.0	20,440	70%	$ 463.22	$ 573.01	$ 109.79	24%	5%
40.0	23,360	80%	$ 520.34	$ 642.24	$ 121.90	23%	5%
50.0	7,300	20%	$ 223.92	$ 283.91	$ 59.99	27%	5%
50.0	10,950	30%	$ 295.31	$ 370.45	$ 75.14	25%	5%
50.0	14,600	40%	$ 366.70	$ 456.99	$ 90.29	25%	5%
50.0	18,250	50%	$ 438.10	$ 543.54	$ 105.44	24%	5%
50.0	21,900	60%	$ 509.49	$ 630.08	$ 120.59	24%	5%
50.0	25,550	70%	$ 580.89	$ 716.62	$ 135.73	23%	5%
50.0	29,200	80%	$ 652.28	$ 803.16	$ 150.88	23%	5%

*Includes Distribution, Surcharges and SOS (Transmission & Generation) as of March 2023

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Test Period 12 Months Ended December 2022

Line No.	HAGERSTOWN & FREDERICK (Special Lighting Contracts)	Current Billing Determinants *[a]*	Current Rate *[b]*	Current Revenue *[c]=[a]x[b]*	Weather Norm Adjustment *[d]*	Pro Forma Norm Billing Determinants *[e]=[a]+[d]*	Pro Forma Rate *[f]*	Pro Forma Revenue *[g]=[e]x[f]*	Revenue Change *[h]=[g]-[c]*	Percent Change *[i]=[h]/[c]*
1	Distribution									
2	Energy Charge (kWh)									
3	All kWh	1,157,521	$ 0.01844	$ 21,345	-	1,157,521	$ 0.02428	$ 28,104	$ 6,759	31.67%
4	Unbilled	6,374		$ 118		6,374		$ 155	$ 37	31.67%
5	Franchise Tax Surcharge			$ 722				$ 722	$ -	0.00%
6	Montgomery County Energy Tax			$ -				$ -	$ -	
7	TOTAL HAGERSTOWN & FREDERICK			$ 22,184				$ 28,980	$ 6,796	30.64%
8	Per Books Revenue			$ 22,208				$ 29,012	$ 6,804	30.64%
9	Correction Factor			0.99890				0.99890		

Total Target	$ 29,012
Total Adj. Target	$ 28,980
Base Adj. Target	$ 28,259
Base Current	$ 21,462

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Test Period 12 Months Ended December 2022

Line No.		Current Billing Determinants	Current Rate	Current Revenue	Weather Norm Adjustment	Pro Forma Norm Billing Determinants	Pro Forma Rate	Pro Forma Revenue	Revenue Change	Percent Change
	SCHEDULE C-A (General Service - All Electric)	*[a]*	*[b]*	*[c]=[a]x[b]*	*[d]*	*[e]=[a]+[d]*	*[f]*	*[g]=[e]x[f]*	*[h]=[g]-[c]*	*[i]=[h]/[c]*
1	Distribution									
2	Fixed Distribution Charge	2,515	$ 4.00	$ 10,061		2,515	$ 8.00	$ 20,121	$ 10,061	100.00%
3	Minimum kW	1,960	$ 1.09	$ 2,136		1,960	$ 1.44	$ 2,816	$ 680	31.86%
4	kWh in Minimum	24,135	$ -	$ -	6	24,141	$ -	$ -	$ -	
5	Energy Charge (kWh)									
6	All kWh	12,847,061	$ 0.01757	$ 225,723	3,306	12,850,367	$ 0.02317	$ 297,711	$ 71,988	31.89%
7	Voltage Discount (kW)									
8	2 kV to 15 kV	15,336	$ (0.25)	$ (3,834)		15,336	$ (0.25)	$ (3,834)	$ -	0.00%
9	CSH (Church & School Space Heating)									
10	Fixed Distribution Charge	1,407	$ 4.00	$ 5,628		1,407	$ 8.00	$ 11,256	$ 5,628	100.00%
11	Energy Charge (kWh)									
12	All kWh	10,447,069	$ 0.01357	$ 141,767	2,694	10,449,763	$ 0.01789	$ 186,979	$ 45,213	31.89%
13	Unbilled	66,093		$ 656		66,093		$ 885	$ 230	35.01%
14	Franchise Tax Surcharge			$ 14,498				$ 14,498	$ -	0.00%
15	Montgomery County Energy Tax			$ 38,374				$ 38,374	$ -	0.00%
16	TOTAL SCHEDULE C-A			$ 435,008				$ 568,808	$ 133,800	30.76%
17	Per Books Revenue			$ 435,542				$ 569,506	$ 133,964	30.76%
18	Correction Factor			0.99877				0.99877		
									35.34%	
									34.49%	

Total Target	$	569,506
Total Adj. Target	$	568,808
Base Adj. Target	$	515,936
Base Current	$	382,136

The Potomac Edison Company (Maryland)
Typical Bill Comparison

Schedule C-A							
Demand kW	Energy kWh	Load Factor	Distribution Current Bill	Distribution Proposed Bill	Distribution Incr/(Decr)	Distribution % Change	Total Bill* % Change
5.0	730	20%	$ 13.72	$ 24.91	$ 11.19	82%	8%
5.0	1,095	30%	$ 20.58	$ 33.37	$ 12.79	62%	7%
5.0	1,460	40%	$ 27.43	$ 41.83	$ 14.40	52%	7%
5.0	1,825	50%	$ 34.29	$ 50.29	$ 16.00	47%	6%
5.0	2,190	60%	$ 41.15	$ 58.74	$ 17.59	43%	6%
5.0	2,555	70%	$ 48.01	$ 67.20	$ 19.19	40%	6%
5.0	2,920	80%	$ 54.87	$ 75.66	$ 20.79	38%	6%
7.5	1,095	20%	$ 20.58	$ 33.37	$ 12.79	62%	7%
7.5	1,643	30%	$ 30.87	$ 46.07	$ 15.20	49%	7%
7.5	2,190	40%	$ 41.15	$ 58.74	$ 17.59	43%	6%
7.5	2,738	50%	$ 51.45	$ 71.44	$ 19.99	39%	6%
7.5	3,285	60%	$ 61.73	$ 84.11	$ 22.38	36%	6%
7.5	3,833	70%	$ 72.02	$ 96.81	$ 24.79	34%	5%
7.5	4,380	80%	$ 82.30	$ 109.48	$ 27.18	33%	5%
10.0	1,460	20%	$ 27.43	$ 41.83	$ 14.40	52%	6%
10.0	2,190	30%	$ 41.15	$ 58.74	$ 17.59	43%	6%
10.0	2,920	40%	$ 54.87	$ 75.66	$ 20.79	38%	6%
10.0	3,650	50%	$ 68.58	$ 92.57	$ 23.99	35%	5%
10.0	4,380	60%	$ 82.30	$ 109.48	$ 27.18	33%	5%
10.0	5,110	70%	$ 96.02	$ 126.40	$ 30.38	32%	5%
10.0	5,840	80%	$ 109.73	$ 143.31	$ 33.58	31%	5%
20.0	2,920	20%	$ 54.87	$ 75.66	$ 20.79	38%	5%
20.0	4,380	30%	$ 82.30	$ 109.48	$ 27.18	33%	5%
20.0	5,840	40%	$ 109.73	$ 143.31	$ 33.58	31%	5%
20.0	7,300	50%	$ 137.17	$ 177.14	$ 39.97	29%	5%
20.0	8,760	60%	$ 164.60	$ 210.97	$ 46.37	28%	4%
20.0	10,220	70%	$ 192.03	$ 244.80	$ 52.77	27%	4%
20.0	11,680	80%	$ 219.47	$ 278.63	$ 59.16	27%	4%
30.0	4,380	20%	$ 82.30	$ 109.48	$ 27.18	33%	4%
30.0	6,570	30%	$ 123.45	$ 160.23	$ 36.78	30%	4%
30.0	8,760	40%	$ 164.60	$ 210.97	$ 46.37	28%	4%
30.0	10,950	50%	$ 205.75	$ 261.71	$ 55.96	27%	4%
30.0	13,140	60%	$ 246.90	$ 312.45	$ 65.55	27%	4%
30.0	15,330	70%	$ 288.05	$ 363.20	$ 75.15	26%	4%
30.0	17,520	80%	$ 329.20	$ 413.94	$ 84.74	26%	4%
40.0	5,840	20%	$ 109.73	$ 143.31	$ 33.58	31%	4%
40.0	8,760	30%	$ 164.60	$ 210.97	$ 46.37	28%	4%
40.0	11,680	40%	$ 219.47	$ 278.63	$ 59.16	27%	4%
40.0	14,600	50%	$ 274.33	$ 346.28	$ 71.95	26%	4%
40.0	17,520	60%	$ 329.20	$ 413.94	$ 84.74	26%	4%
40.0	20,440	70%	$ 384.07	$ 481.59	$ 97.52	25%	4%
40.0	23,360	80%	$ 438.93	$ 549.25	$ 110.32	25%	4%
50.0	7,300	20%	$ 137.17	$ 177.14	$ 39.97	29%	4%
50.0	10,950	30%	$ 205.75	$ 261.71	$ 55.96	27%	4%
50.0	14,600	40%	$ 274.33	$ 346.28	$ 71.95	26%	4%
50.0	18,250	50%	$ 342.92	$ 430.85	$ 87.93	26%	4%
50.0	21,900	60%	$ 411.50	$ 515.42	$ 103.92	25%	4%
50.0	25,550	70%	$ 480.08	$ 599.99	$ 119.91	25%	4%
50.0	29,200	80%	$ 548.67	$ 684.56	$ 135.89	25%	4%

*Includes Distribution, Surcharges and SOS (Transmission & Generation) as of March 2023

The Potomac Edison Company (Maryland)
Typical Bill Comparison

Schedule CSH					
Energy kWh	Distribution Current Bill	Distribution Proposed Bill	Distribution Incr/(Decr)	Distribution % Change	Total Bill* % Change
1,000	$ 18.79	$ 25.89	$ 7.10	38%	6%
2,000	$ 33.58	$ 43.78	$ 10.20	30%	4%
3,000	$ 48.37	$ 61.67	$ 13.30	27%	4%
4,000	$ 63.16	$ 79.56	$ 16.40	26%	4%
5,000	$ 77.95	$ 97.45	$ 19.50	25%	3%
6,000	$ 92.74	$ 115.34	$ 22.60	24%	3%
7,000	$ 107.53	$ 133.23	$ 25.70	24%	3%
8,000	$ 122.32	$ 151.12	$ 28.80	24%	3%
9,000	$ 137.11	$ 169.01	$ 31.90	23%	3%
10,000	$ 151.90	$ 186.90	$ 35.00	23%	3%
11,000	$ 166.69	$ 204.79	$ 38.10	23%	3%
12,000	$ 181.48	$ 222.68	$ 41.20	23%	3%
13,000	$ 196.27	$ 240.57	$ 44.30	23%	3%
14,000	$ 211.06	$ 258.46	$ 47.40	22%	3%
15,000	$ 225.85	$ 276.35	$ 50.50	22%	3%
16,000	$ 240.64	$ 294.24	$ 53.60	22%	3%
17,000	$ 255.43	$ 312.13	$ 56.70	22%	3%
18,000	$ 270.22	$ 330.02	$ 59.80	22%	3%
19,000	$ 285.01	$ 347.91	$ 62.90	22%	3%
20,000	$ 299.80	$ 365.80	$ 66.00	22%	3%
21,000	$ 314.59	$ 383.69	$ 69.10	22%	3%
22,000	$ 329.38	$ 401.58	$ 72.20	22%	3%
23,000	$ 344.17	$ 419.47	$ 75.30	22%	3%
24,000	$ 358.96	$ 437.36	$ 78.40	22%	3%
25,000	$ 373.75	$ 455.25	$ 81.50	22%	3%
26,000	$ 388.54	$ 473.14	$ 84.60	22%	3%
27,000	$ 403.33	$ 491.03	$ 87.70	22%	3%
28,000	$ 418.12	$ 508.92	$ 90.80	22%	3%
29,000	$ 432.91	$ 526.81	$ 93.90	22%	3%
30,000	$ 447.70	$ 544.70	$ 97.00	22%	3%

*Includes Distribution, Surcharges and SOS (Transmission & Generation) as of March 2023

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Test Period 12 Months Ended December 2022

Line No.		Current: Billing Determinants	Current: Rate	Current: Revenue	Weather Norm Adjustment	Pro Forma: Norm Billing Determinants	Pro Forma: Rate	Pro Forma: Revenue	Revenue Change	Percent Change
	SCHEDULE PH (Power Service)	*[a]*	*[b]*	*[c]=[a]x[b]*	*[d]*	*[e]=[a]+[d]*	*[f]*	*[g]=[e]x[f]*	*[h]=[g]-[c]*	*[i]=[h]/[c]*
1	Distribution									
2	Fixed Distribution Charge	20,167	$ -	$ -		20,167	$ 17.00	$ 342,839	$ 342,839	
3	Minimum kW	27,928	$ 1.14	$ 31,838		27,928	$ 1.54	$ 43,114	$ 11,276	35.42%
4	kWh in Minimum	855,103	$ -	$ -	219	855,322	$ -	$ -	$ -	
5	Capacity Charge (kW)									
6	All kW	4,399,978	$ 1.78	$ 7,831,960		4,399,978	$ 2.41	$ 10,605,838	$ 2,773,877	35.42%
7	Energy Charge (kWh)									
8	All kWh	1,798,447,287	$ 0.00386	$ 6,942,007	461,553	1,798,908,840	$ 0.00523	$ 9,403,098	$ 2,461,091	35.45%
9	Voltage Discount (kW)									
10	2 kV to 15 kV	656,641	$ (0.25)	$ (164,160)		656,641	$ (0.25)	$ (164,160)	$ -	0.00%
11	Over 15 kV	168,302	$ (0.50)	$ (84,151)		168,302	$ (0.50)	$ (84,151)	$ -	0.00%
12	Reactive kVA Charge (kVAR)									
13	Billing kVAR	909,857	$ 0.40	$ 363,943		909,857	$ 0.40	$ 363,943	$ -	0.00%
14	Unbilled	3,351,544		$ 31,487		3,351,544		$ 43,281	$ 11,794	37.46%
15	Franchise Tax Surcharge			$ 1,117,645				$ 1,117,645	$ -	0.00%
16	Montgomery County Energy Tax			$ 3,146,485				$ 3,146,485	$ -	0.00%
17	TOTAL SCHEDULE PH			$ 19,217,053				$ 24,817,931	$ 5,600,878	29.15%
18	Per Books Revenue			$ 19,356,146				$ 24,997,563	$ 5,641,417	29.15%
19	Correction Factor			0.99281				0.99281		

Total Target	$ 24,997,563
Total Adj. Target	$ 24,817,931
Base Adj. Target	**$ 20,553,801**
Base Current	$ 14,952,923

The Potomac Edison Company (Maryland)
Typical Bill Comparison

Schedule PH										
Demand kW	Energy kWh	Load Factor		Distribution Current Bill		Distribution Proposed Bill		Distribution Incr/(Decr)	Distribution % Change	Total Bill* % Change
50.0	14,600	40%	$	153.82	$	213.86	$	60.04	39%	4%
50.0	18,250	50%	$	170.03	$	232.95	$	62.92	37%	4%
50.0	21,900	60%	$	186.24	$	252.04	$	65.80	35%	3%
50.0	25,550	70%	$	202.44	$	271.13	$	68.69	34%	3%
50.0	29,200	80%	$	218.65	$	290.22	$	71.57	33%	3%
50.0	32,850	90%	$	234.85	$	309.31	$	74.46	32%	3%
75.0	21,900	40%	$	230.74	$	312.29	$	81.55	35%	3%
75.0	27,375	50%	$	255.05	$	340.92	$	85.87	34%	3%
75.0	32,850	60%	$	279.35	$	369.56	$	90.21	32%	3%
75.0	38,325	70%	$	303.66	$	398.19	$	94.53	31%	3%
75.0	43,800	80%	$	327.97	$	426.82	$	98.85	30%	3%
75.0	49,275	90%	$	352.28	$	455.46	$	103.18	29%	3%
100.0	29,200	40%	$	307.65	$	410.72	$	103.07	34%	3%
100.0	36,500	50%	$	340.06	$	448.90	$	108.84	32%	3%
100.0	43,800	60%	$	372.47	$	487.07	$	114.60	31%	3%
100.0	51,100	70%	$	404.88	$	525.25	$	120.37	30%	3%
100.0	58,400	80%	$	437.30	$	563.43	$	126.13	29%	3%
100.0	65,700	90%	$	469.71	$	601.61	$	131.90	28%	3%
250.0	73,000	40%	$	769.12	$	1,001.29	$	232.17	30%	3%
250.0	91,250	50%	$	850.15	$	1,096.74	$	246.59	29%	3%
250.0	109,500	60%	$	931.18	$	1,192.19	$	261.01	28%	3%
250.0	127,750	70%	$	1,012.21	$	1,287.63	$	275.42	27%	3%
250.0	146,000	80%	$	1,093.24	$	1,383.08	$	289.84	27%	3%
250.0	164,250	90%	$	1,174.27	$	1,478.53	$	304.26	26%	3%
500.0	146,000	40%	$	1,538.24	$	1,985.58	$	447.34	29%	3%
500.0	182,500	50%	$	1,700.30	$	2,176.48	$	476.18	28%	3%
500.0	219,000	60%	$	1,862.36	$	2,367.37	$	505.01	27%	3%
500.0	255,500	70%	$	2,024.42	$	2,558.27	$	533.85	26%	3%
500.0	292,000	80%	$	2,186.48	$	2,749.16	$	562.68	26%	3%
500.0	328,500	90%	$	2,348.54	$	2,940.06	$	591.52	25%	2%
1,000.0	292,000	40%	$	3,076.48	$	3,954.16	$	877.68	29%	3%
1,000.0	365,000	50%	$	3,400.60	$	4,335.95	$	935.35	28%	3%
1,000.0	438,000	60%	$	3,724.72	$	4,717.74	$	993.02	27%	2%
1,000.0	511,000	70%	$	4,048.84	$	5,099.53	$	1,050.69	26%	2%
1,000.0	584,000	80%	$	4,372.96	$	5,481.32	$	1,108.36	25%	2%
1,000.0	657,000	90%	$	4,697.08	$	5,863.11	$	1,166.03	25%	2%
2,000.0	584,000	40%	$	6,152.96	$	7,891.32	$	1,738.36	28%	3%
2,000.0	730,000	50%	$	6,801.20	$	8,654.90	$	1,853.70	27%	3%
2,000.0	876,000	60%	$	7,449.44	$	9,418.48	$	1,969.04	26%	2%
2,000.0	1,022,000	70%	$	8,097.68	$	10,182.06	$	2,084.38	26%	2%
2,000.0	1,168,000	80%	$	8,745.92	$	10,945.64	$	2,199.72	25%	2%
2,000.0	1,314,000	90%	$	9,394.16	$	11,709.22	$	2,315.06	25%	2%
3,000.0	876,000	40%	$	9,229.44	$	11,828.48	$	2,599.04	28%	3%
3,000.0	1,095,000	50%	$	10,201.80	$	12,973.85	$	2,772.05	27%	3%
3,000.0	1,314,000	60%	$	11,174.16	$	14,119.22	$	2,945.06	26%	2%
3,000.0	1,533,000	70%	$	12,146.52	$	15,264.59	$	3,118.07	26%	2%
3,000.0	1,752,000	80%	$	13,118.88	$	16,409.96	$	3,291.08	25%	2%
3,000.0	1,971,000	90%	$	14,091.24	$	17,555.33	$	3,464.09	25%	2%
4,000.0	1,168,000	40%	$	12,305.92	$	15,765.64	$	3,459.72	28%	3%
4,000.0	1,460,000	50%	$	13,602.40	$	17,292.80	$	3,690.40	27%	3%
4,000.0	1,752,000	60%	$	14,898.88	$	18,819.96	$	3,921.08	26%	2%
4,000.0	2,044,000	70%	$	16,195.36	$	20,347.12	$	4,151.76	26%	2%
4,000.0	2,336,000	80%	$	17,491.84	$	21,874.28	$	4,382.44	25%	2%
4,000.0	2,628,000	90%	$	18,788.32	$	23,401.44	$	4,613.12	25%	2%
5,000.0	1,460,000	40%	$	15,382.40	$	19,702.80	$	4,320.40	28%	3%
5,000.0	1,825,000	50%	$	17,003.00	$	21,611.75	$	4,608.75	27%	3%
5,000.0	2,190,000	60%	$	18,623.60	$	23,520.70	$	4,897.10	26%	2%
5,000.0	2,555,000	70%	$	20,244.20	$	25,429.65	$	5,185.45	26%	2%
5,000.0	2,920,000	80%	$	21,864.80	$	27,338.60	$	5,473.80	25%	2%
5,000.0	3,285,000	90%	$	23,485.40	$	29,247.55	$	5,762.15	25%	2%

*Includes Distribution, Surcharges and SOS (Transmission & Generation) as of March 2023

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Test Period 12 Months Ended December 2022

		Current				Pro Forma				
Line No.		Billing Determinants	Rate	Revenue	Weather Norm Adjustment	Norm Billing Determinants	Rate	Revenue	Revenue Change	Percent Change
	SCHEDULE AGS (Alternative Generation Service)	*[a]*	*[b]*	*[c]=[a]x[b]*	*[d]*	*[e]=[a]+[d]*	*[f]*	*[g]=[e]x[f]*	*[h]=[g]-[c]*	*[i]=[h]/[c]*
1	Distribution									
2	Fixed Distribution Charge	12	$ -	$ -		12	$ 17.00	$ 204	$ 204	
3	kWh in Minimum	3,733,958	$ -	$ -		3,733,958	$ -	$ -	$ -	
4	Firm Standby Charge (kW)									
5	All kW	7,200	$ 0.906	$ 6,523		7,200	$ 1.216	$ 8,758	$ 2,234	34.25%
6	Interruptible Standby Charge (kW)									
7	All kW	0	$ 0.857	$ -		0	$ 1.151	$ -	$ -	
8	Firm or Interruptible Maintenance Charge (kW)									
9	All kW	0	$ 0.845	$ -		0	$ 1.134	$ -	$ -	
10	Energy Charge (kWh)									
11	All kWh	0	$ 0.00151	$ -	-	0	$ 0.00203	$ -	$ -	
12	Reactive kVA Charge (kVAR)									
13	Billing kVAR	0	$ 0.40	$ -		0	$ 0.40	$ -	$ -	
14	Unbilled	0		$ -		0		$ 0	$ -	
15	Franchise Tax Surcharge			$ 13				$ 13	$ -	0.00%
16	Montgomery County Energy Tax			$ -				$ -	$ -	
17	TOTAL SCHEDULE AGS			$ 6,536				$ 8,974	$ 2,438	37.31%
18	Per Books Revenue			$ 6,578				$ 9,032	$ 2,454	37.31%
19	Correction Factor			0.99360				0.99360		

Total Target	$ 9,032	37.38%
Total Adj. Target	$ 8,974	
Base Adj. Target	$ 8,962	
Base Current	$ 6,523	

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Test Period 12 Months Ended December 2022

Line No.		Current			Weather Norm	Pro Forma				
		Billing Determinants	Rate	Revenue	Weather Norm Adjustment	Norm Billing Determinants	Rate	Revenue	Revenue Change	Percent Change
	SCHEDULE PP (Large Power Service)	*[a]*	*[b]*	*[c]=[a]x[b]*	*[d]*	*[e]=[a]+[d]*	*[f]*	*[g]=[e]x[f]*	*[h]=[g]-[c]*	*[i]=[h]/[c]*
1	Distribution									
2	Fixed Distribution Charge	121	$ -	$ -		121	$ 453.00	$ 54,813	$ 54,813	
3	Capacity Charge (kW)									
4	All kW	1,554,198	$ 0.286	$ 444,501		1,554,198	$ 0.402	$ 625,094	$ 180,593	40.63%
5	Energy Charge (kWh)									
6	All kWh	709,402,478	$ 0.00059	$ 418,547	183,813	709,586,291	$ 0.00083	$ 588,749	$ 170,201	40.66%
7	Reactive kVA Charge (kVAR)									
8	Billing kVAR	208,774	$ 0.40	$ 83,510		208,774	$ 0.40	$ 83,510	$ -	0.00%
9	Unbilled	(5,063,385)		$ (10,631)		(5,063,385)		$ (15,186)	$ (4,555)	42.85%
10	Franchise Tax Surcharge			$ 436,690				$ 436,690	$ -	0.00%
11	Montgomery County Energy Tax			$ -				$ -	$ -	
12	TOTAL SCHEDULE PP			$ 1,372,617				$ 1,773,669	$ 401,052	29.22%
13	Per Books Revenue			$ 1,374,959				$ 1,776,695	$ 401,736	29.22%
14	Correction Factor			0.99830				0.99830		

Total Target	$ 1,776,695	42.85%
Total Adj. Target	$ 1,773,669	
Base Adj. Target	**$ 1,336,979**	
Base Current	$ 935,927	

The Potomac Edison Company (Maryland)
Typical Bill Comparison

Schedule PP							
Demand kW	Energy kWh	Load Factor	Distribution Current Bill	Distribution Proposed Bill	Distribution Incr/(Decr)	Distribution % Change	Total Bill* % Change
5,000.0	1,825,000	50%	$ 2,543.25	$ 3,977.75	$ 1,434.50	56%	1%
5,000.0	2,190,000	60%	$ 2,765.90	$ 4,280.70	$ 1,514.80	55%	1%
5,000.0	2,555,000	70%	$ 2,988.55	$ 4,583.65	$ 1,595.10	53%	1%
5,000.0	2,920,000	80%	$ 3,211.20	$ 4,886.60	$ 1,675.40	52%	1%
5,000.0	3,285,000	90%	$ 3,433.85	$ 5,189.55	$ 1,755.70	51%	1%
5,000.0	3,650,000	100%	$ 3,656.50	$ 5,492.50	$ 1,836.00	50%	1%
7,500.0	2,737,500	50%	$ 3,814.88	$ 5,740.13	$ 1,925.25	50%	1%
7,500.0	3,285,000	60%	$ 4,148.85	$ 6,194.55	$ 2,045.70	49%	1%
7,500.0	3,832,500	70%	$ 4,482.83	$ 6,648.98	$ 2,166.15	48%	1%
7,500.0	4,380,000	80%	$ 4,816.80	$ 7,103.40	$ 2,286.60	47%	1%
7,500.0	4,927,500	90%	$ 5,150.78	$ 7,557.83	$ 2,407.05	47%	1%
7,500.0	5,475,000	100%	$ 5,484.75	$ 8,012.25	$ 2,527.50	46%	1%
10,000.0	3,650,000	50%	$ 5,086.50	$ 7,502.50	$ 2,416.00	47%	1%
10,000.0	4,380,000	60%	$ 5,531.80	$ 8,108.40	$ 2,576.60	47%	1%
10,000.0	5,110,000	70%	$ 5,977.10	$ 8,714.30	$ 2,737.20	46%	1%
10,000.0	5,840,000	80%	$ 6,422.40	$ 9,320.20	$ 2,897.80	45%	1%
10,000.0	6,570,000	90%	$ 6,867.70	$ 9,926.10	$ 3,058.40	45%	1%
10,000.0	7,300,000	100%	$ 7,313.00	$ 10,532.00	$ 3,219.00	44%	1%
20,000.0	7,300,000	50%	$ 10,173.00	$ 14,552.00	$ 4,379.00	43%	1%
20,000.0	8,760,000	60%	$ 11,063.60	$ 15,763.80	$ 4,700.20	42%	1%
20,000.0	10,220,000	70%	$ 11,954.20	$ 16,975.60	$ 5,021.40	42%	1%
20,000.0	11,680,000	80%	$ 12,844.80	$ 18,187.40	$ 5,342.60	42%	1%
20,000.0	13,140,000	90%	$ 13,735.40	$ 19,399.20	$ 5,663.80	41%	1%
20,000.0	14,600,000	100%	$ 14,626.00	$ 20,611.00	$ 5,985.00	41%	0%
30,000.0	10,950,000	50%	$ 15,259.50	$ 21,601.50	$ 6,342.00	42%	1%
30,000.0	13,140,000	60%	$ 16,595.40	$ 23,419.20	$ 6,823.80	41%	1%
30,000.0	15,330,000	70%	$ 17,931.30	$ 25,236.90	$ 7,305.60	41%	1%
30,000.0	17,520,000	80%	$ 19,267.20	$ 27,054.60	$ 7,787.40	40%	1%
30,000.0	19,710,000	90%	$ 20,603.10	$ 28,872.30	$ 8,269.20	40%	1%
30,000.0	21,900,000	100%	$ 21,939.00	$ 30,690.00	$ 8,751.00	40%	0%
40,000.0	14,600,000	50%	$ 20,346.00	$ 28,651.00	$ 8,305.00	41%	1%
40,000.0	17,520,000	60%	$ 22,127.20	$ 31,074.60	$ 8,947.40	40%	1%
40,000.0	20,440,000	70%	$ 23,908.40	$ 33,498.20	$ 9,589.80	40%	1%
40,000.0	23,360,000	80%	$ 25,689.60	$ 35,921.80	$ 10,232.20	40%	1%
40,000.0	26,280,000	90%	$ 27,470.80	$ 38,345.40	$ 10,874.60	40%	0%
40,000.0	29,200,000	100%	$ 29,252.00	$ 40,769.00	$ 11,517.00	39%	0%
50,000.0	18,250,000	50%	$ 25,432.50	$ 35,700.50	$ 10,268.00	40%	1%
50,000.0	21,900,000	60%	$ 27,659.00	$ 38,730.00	$ 11,071.00	40%	1%
50,000.0	25,550,000	70%	$ 29,885.50	$ 41,759.50	$ 11,874.00	40%	1%
50,000.0	29,200,000	80%	$ 32,112.00	$ 44,789.00	$ 12,677.00	39%	1%
50,000.0	32,850,000	90%	$ 34,338.50	$ 47,818.50	$ 13,480.00	39%	0%
50,000.0	36,500,000	100%	$ 36,565.00	$ 50,848.00	$ 14,283.00	39%	0%

*Includes Distribution, Surcharges and SOS (Transmission & Generation) as of March 2023

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Street & Area Lighting Rate Schedules

		Current			Pro Forma				
	kWh	Facility Counts	Rate	Revenue	Facility Counts	Rate	Revenue	Revenue Change	Percent Change
SCHEDULE EMU	*[a]*	*[b]*	*[c]*	*[d]=[b]x[c]*	*[e]*	*[f]*	*[g]=[e]x[f]*	*[h]=[g]-[d]*	*[i]=[h]/[d]*
(Equipment, Maintenance & Unmetered Svc)									
Overhead Service									
HPS-Vertical Open Lens Luminaire/OL									
9,500 Lumen (100 Watt)									
With Pole	51	106	$ 17.41	$ 1,845	106	$ 20.56	$ 2,179	$ 333	18.07%
9,500 Lumen (100 Watt)									
Without Pole	51	958	$ 8.81	$ 8,440	958	$ 10.40	$ 9,965	$ 1,525	18.07%
MH-Horizontal/Cobra Head									
8,150 Lumen (175 Watt)	74	26	$ 7.98	$ 207	26	$ 9.42	$ 244	$ 37	18.07%
HPS-Horizontal/Cobra Head									
9,500 Lumen (100 Watt)	51	174	$ 9.13	$ 1,589	174	$ 10.78	$ 1,876	$ 287	18.07%
22,000 Lumen (200 Watt)	86	78	$ 13.92	$ 1,087	78	$ 16.44	$ 1,283	$ 196	18.07%
50,000 Lumen (400 Watt)	167	40	$ 19.57	$ 781	40	$ 23.11	$ 922	$ 141	18.07%
MH-Horizontal/Cobra Head									
36,000 Lumen (400 Watt)	157	38	$ 21.28	$ 812	38	$ 25.13	$ 959	$ 147	18.07%
90,000 Lumen (1,000 Watt)	379	30	$ 21.58	$ 647	30	$ 25.48	$ 764	$ 117	18.07%
HPS Floodlight									
22,000 Lumen (200 Watt)	86	46	$ 15.66	$ 716	46	$ 18.49	$ 846	$ 129	18.07%
50,000 Lumen(400 Watt)	167	56	$ 23.60	$ 1,322	56	$ 27.86	$ 1,560	$ 239	18.07%
MH Floodlight									
36,000 Lumen (400 Watt)	157	47	$ 24.77	$ 1,164	47	$ 29.25	$ 1,375	$ 210	18.07%
90,000 Lumen (1,000 Watt)	379	42	$ 23.94	$ 1,006	42	$ 28.27	$ 1,187	$ 182	18.07%
Underground Service									
HPS Colonial Post Top 14' Mounting Height									
9,500 Lumen (100 Watt)	51	704	$ 16.28	$ 11,461	704	$ 19.22	$ 13,532	$ 2,071	18.07%
MV Colonial Post Top 14' Mounting Height									
11,600 Lumen (175 Watt)	74	36	$ 22.75	$ 811	36	$ 26.86	$ 958	$ 147	18.07%
HPS Cobra Head/30' Mounting Height									
Single Luminaire Per Pole									
9,500 Lumen (100 Watt)	51	56	$ 24.34	$ 1,363	56	$ 28.74	$ 1,609	$ 246	18.07%
22,000 Lumen (200 Watt)	86	28	$ 27.14	$ 760	28	$ 32.04	$ 897	$ 137	18.07%
50,000 Lumen (400 Watt)	167	3	$ 32.79	$ 98	3	$ 38.72	$ 116	$ 18	18.07%
Each Additional Luminaire Per Pole									
9,500 Lumen (100 Watt)	51	-	$ 9.13	$ -	-	$ 10.78	$ -	$ -	18.07%
22,000 Lumen (200 Watt)	86	-	$ 13.92	$ -	-	$ 16.44	$ -	$ -	18.07%
50,000 Lumen (400 Watt)	167	-	$ 19.57	$ -	-	$ 23.11	$ -	$ -	18.07%
MH Horizontal Cobra Head/30' Mounting Height									
Single Luminaire Per Pole									
36,000 Lumen (400 Watt)	157	3	$ 34.29	$ 103	3	$ 40.49	$ 121	$ 19	18.07%
90,000 Lumen (1,000 Watt)	379	6	$ 42.51	$ 255	6	$ 50.19	$ 301	$ 46	18.07%
Each Additional Luminaire Per Pole									
36,000 Lumen (400 Watt)	157	-	$ 21.28	$ -	-	$ 25.13	$ -	$ -	18.07%
90,000 Lumen (1,000 Watt)	379	-	$ 21.58	$ -	-	$ 25.48	$ -	$ -	18.07%
HPS-Shoe Box/30' Mounting Height									
With Base									
9,500 Lumen (100 Watt)	51	17	$ 39.36	$ 669	17	$ 46.47	$ 790	$ 121	18.07%
22,000 Lumen (200 Watt)	86	83	$ 39.91	$ 3,313	83	$ 47.12	$ 3,911	$ 599	18.07%
50,000 Lumen (400 Watt)	167	1	$ 40.04	$ 27	1	$ 47.28	$ 32	$ 5	18.07%
No Base									
9,500 Lumen (100 Watt)	51	1	$ 37.57	$ 38	1	$ 44.36	$ 44	$ 7	18.07%
22,000 Lumen (200 Watt)	86	28	$ 38.37	$ 1,074	28	$ 45.30	$ 1,269	$ 194	18.07%
50,000 Lumen (400 Watt)	167	17	$ 36.77	$ 625	17	$ 43.41	$ 738	$ 113	18.07%
Each Additional Luminaire Per Pole									
9,500 Lumen (100 Watt)	51	6	$ 20.72	$ 124	6	$ 24.46	$ 147	$ 22	18.07%
22,000 Lumen (200 Watt)	86	-	$ 21.56	$ -	-	$ 25.46	$ -	$ -	18.07%
50,000 Lumen (400 Watt)	167	1	$ 19.95	$ 20	1	$ 23.56	$ 24	$ 4	18.07%

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Street & Area Lighting Rate Schedules

		Current			Pro Forma				
	kWh	Facility Counts	Rate	Revenue	Facility Counts	Rate	Revenue	Revenue Change	Percent Change
MH Shoe Box/30' Mounting Height									
With Base									
36,000 Lumen (400 Watt)	157	-	$ 41.68	$ -	-	$ 49.21	$ -	$ -	18.07%
No Base									
36,000 Lumen (400 Watt)	157	-	$ 37.77	$ -	-	$ 44.60	$ -	$ -	18.07%
Each Additional Luminaire Per Pole									
36,000 Lumen (400 Watt)	157	-	$ 21.54	$ -	-	$ 25.43	$ -	$ -	18.07%
MH Shoe Box/40' Mounting Height									
No Base									
90,000 Lumen (1,000 Watt)	379	-	$ 47.05	$ -	-	$ 55.55	$ -	$ -	18.07%
Each Additional Luminaire Per Pole									
90,000 Lumen(1,000 Watt)	379	-	$ 28.00	$ -	-	$ 33.06	$ -	$ -	18.07%
SCHEDULE EMU - Long Term Service									
(Equipment, Maintenance & Unmetered Svc)									
Overhead Service									
HPS-Vertical Open Lens Luminaire/OL									
9,500 Lumen (100 Watt)									
With Pole	51	17	$ 16.91	$ 286	17	$ 20.06	$ 339	$ 53	18.61%
9,500 Lumen (100 Watt)									
Without Pole	51	227	$ 8.31	$ 1,886	227	$ 9.90	$ 2,248	$ 361	19.16%
MV-Horizontal/Cobra Head									
8,150 Lumen (175 Watt)	74	12	$ 7.48	$ 90	12	$ 8.92	$ 107	$ 17	19.28%
HPS-Horizontal/Cobra Head									
9,500 Lumen (100 Watt)	51	2,484	$ 8.63	$ 21,437	2,484	$ 10.28	$ 25,535	$ 4,098	19.12%
22,000 Lumen (200 Watt)	86	454	$ 13.42	$ 6,093	454	$ 15.94	$ 7,235	$ 1,142	18.74%
50,000 Lumen (400 Watt)	167	53	$ 19.07	$ 1,006	53	$ 22.61	$ 1,193	$ 187	18.54%
MH-Horizontal/Cobra Head									
36,000 Lumen (400 Watt)	157	5	$ 20.78	$ 104	5	$ 24.63	$ 123	$ 19	18.51%
90,000 Lumen (1,000 Watt)	379	-	$ 21.08	$ -	-	$ 24.98	$ -	$ -	18.50%
HPS Floodlight									
22,000 Lumen (200 Watt)	86	29	$ 15.16	$ 440	29	$ 17.99	$ 522	$ 82	18.67%
50,000 Lumen(400 Watt)	167	32	$ 23.10	$ 732	32	$ 27.36	$ 867	$ 135	18.46%
MH Floodlight									
36,000 Lumen (400 Watt)	157	16	$ 24.27	$ 388	16	$ 28.75	$ 460	$ 72	18.44%
90,000 Lumen (1,000 Watt)	379	11	$ 23.44	$ 258	11	$ 27.77	$ 305	$ 48	18.46%
Underground Service									
HPS Colonial Post Top 14' Mounting Height									
9,500 Lumen (100 Watt)	51	4,762	$ 15.78	$ 75,144	4,762	$ 18.72	$ 89,154	$ 14,009	18.64%
MV Colonial Post Top 14' Mounting Height									
11,600 Lumen (175 Watt)	74	601	$ 22.25	$ 13,372	601	$ 26.36	$ 15,843	$ 2,471	18.48%
HPS Cobra Head/30' Mounting Height									
Single Luminaire Per Pole									
9,500 Lumen (100 Watt)	51	26	$ 23.84	$ 620	26	$ 28.24	$ 734	$ 114	18.45%
22,000 Lumen (200 Watt)	86	135	$ 26.64	$ 3,596	135	$ 31.54	$ 4,258	$ 662	18.41%
50,000 Lumen (400 Watt)	167	1	$ 32.29	$ 32	1	$ 38.22	$ 38	$ 6	18.35%
Each Additional Luminaire Per Pole									
9,500 Lumen (100 Watt)	51	-	$ 8.63	$ -	-	$ 10.28	$ -	$ -	19.12%
22,000 Lumen (200 Watt)	86	-	$ 13.42	$ -	-	$ 15.94	$ -	$ -	18.74%
50,000 Lumen (400 Watt)	167	-	$ 19.07	$ -	-	$ 22.61	$ -	$ -	18.54%
MH Horizontal Cobra Head/30' Mounting Height									
Single Luminaire Per Pole									
36,000 Lumen (400 Watt)	157	1	$ 33.79	$ 34	1	$ 39.99	$ 40	$ 6	18.34%
90,000 Lumen (1,000 Watt)	379	-	$ 42.01	$ -	-	$ 49.69	$ -	$ -	18.29%
Each Additional Luminaire Per Pole									
36,000 Lumen (400 Watt)	157	-	$ 20.78	$ -	-	$ 24.63	$ -	$ -	18.51%
90,000 Lumen (1,000 Watt)	379	-	$ 21.08	$ -	-	$ 24.98	$ -	$ -	18.50%
HPS-Shoe Box/30' Mounting Height									
With Base									
9,500 Lumen (100 Watt)	51	-	$ 38.86	$ -	-	$ 45.97	$ -	$ -	18.30%
22,000 Lumen (200 Watt)	86	23	$ 39.41	$ 906	23	$ 46.62	$ 1,072	$ 166	18.30%
50,000 Lumen (400 Watt)	167	2	$ 39.54	$ 79	2	$ 46.78	$ 94	$ 14	18.30%
No Base									
9,500 Lumen (100 Watt)	51	17	$ 37.07	$ 630	17	$ 43.86	$ 746	$ 115	18.31%
22,000 Lumen (200 Watt)	86	426	$ 37.87	$ 16,133	426	$ 44.80	$ 19,086	$ 2,954	18.31%
50,000 Lumen (400 Watt)	167	1	$ 36.27	$ 36	1	$ 42.91	$ 43	$ 7	18.32%
Each Additional Luminaire Per Pole									
9,500 Lumen (100 Watt)	51	4	$ 20.22	$ 81	4	$ 23.96	$ 96	$ 15	18.52%
22,000 Lumen (200 Watt)	86	-	$ 21.06	$ -	-	$ 24.96	$ -	$ -	18.50%
50,000 Lumen (400 Watt)	167	-	$ 19.45	$ -	-	$ 23.06	$ -	$ -	18.54%

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Street & Area Lighting Rate Schedules

		Current			Pro Forma				
	kWh	Facility Counts	Rate	Revenue	Facility Counts	Rate	Revenue	Revenue Change	Percent Change
MH Shoe Box/30' Mounting Height									
With Base									
36,000 Lumen (400 Watt)	157	-	$ 41.18	$ -	-	$ 48.71	$ -	$ -	18.29%
No Base									
36,000 Lumen (400 Watt)	157	113	$ 37.27	$ 4,212	113	$ 44.10	$ 4,983	$ 771	18.31%
Each Additional Luminaire Per Pole									
36,000 Lumen (400 Watt)	157	94	$ 21.04	$ 1,978	94	$ 24.93	$ 2,344	$ 366	18.50%
MH Shoe Box/40' Mounting Height									
No Base									
90,000 Lumen (1,000 Watt)	379	-	$ 46.55	$ -	-	$ 55.05	$ -	$ -	18.26%
Each Additional Luminaire Per Pole									
90,000 Lumen(1,000 Watt)	379	-	$ 27.50	$ -	-	$ 32.56	$ -	$ -	18.40%
SCHEDULE MU									
(Maintenance & Unmetered Service)									
HPS Vapor									
Customer Owned Pole									
9,500 Lumen (100 Watt)	51	1,279	$ 2.71	$ 3,466	1,279	$ 3.20	$ 4,092	$ 626	18.07%
22,000 Lumen (200 Watt)	86	240	$ 2.75	$ 660	240	$ 3.25	$ 779	$ 119	18.07%
50,000 Lumen (400 Watt)	167	69	$ 6.77	$ 467	69	$ 7.99	$ 552	$ 84	18.07%
Company Distr. System									
9,500 Lumen (100 Watt)	51	122	$ 4.08	$ 498	122	$ 4.82	$ 588	$ 90	18.07%
22,000 Lumen (200 Watt)	86	52	$ 4.12	$ 214	52	$ 4.86	$ 253	$ 39	18.07%
50,000 Lumen (400 Watt)	167	-	$ 8.10	$ -	-	$ 9.56	$ -	$ -	18.07%
Mercury Vapor									
Customer Owned Pole									
8,150 Lumen (175 Watt)	74	199	$ 2.58	$ 513	199	$ 3.05	$ 606	$ 93	18.07%
11,500 Lumen (250 Watt)	103	-	$ 5.05	$ -	-	$ 5.96	$ -	$ -	18.07%
21,500 Lumen (400 Watt)	162	-	$ 5.47	$ -	-	$ 6.46	$ -	$ -	18.07%
60,000 Lumen (1,000 Watt)	386	-	$ 7.61	$ -	-	$ 8.99	$ -	$ -	18.07%
Company Distr. System									
8,150 Lumen (175 Watt)	74	1	$ 3.96	$ 4	1	$ 4.68	$ 5	$ 1	18.07%
11,500 Lumen (250 Watt)	103	4	$ 6.42	$ 26	4	$ 7.58	$ 30	$ 5	18.07%
21,500 Lumen (400 Watt)	162	-	$ 6.81	$ -	-	$ 8.04	$ -	$ -	18.07%
60,000 Lumen (1,000 Watt)	386	-	$ 8.95	$ -	-	$ 10.57	$ -	$ -	18.07%
Metal Halide									
Customer Owned Pole									
11,600 Lumen (175 Watt)	74	62	$ 4.20	$ 260	62	$ 4.96	$ 307	$ 47	18.07%
15,000 Lumen (250 Watt)	103	49	$ 4.45	$ 218	49	$ 5.25	$ 257	$ 39	18.07%
36,000 Lumen (400 Watt)	157	8	$ 7.30	$ 58	8	$ 8.62	$ 69	$ 11	18.07%
90,000 Lumen (1,000 Watt)	379	-	$ 8.93	$ -	-	$ 10.54	$ -	$ -	18.07%
Company Distr. System									
11,600 Lumen (175 Watt)	74	-	$ 5.54	$ -	-	$ 6.54	$ -	$ -	18.07%
15,000 Lumen (250 Watt)	103	28	$ 5.80	$ 162	28	$ 6.85	$ 192	$ 29	18.07%
36,000 Lumen (400 Watt)	157	72	$ 8.68	$ 625	72	$ 10.25	$ 738	$ 113	18.07%
90,000 Lumen (1,000 Watt)	379	3	$ 10.27	$ 31	3	$ 12.13	$ 36	$ 6	18.07%
Incandescent									
Customer Owned Pole									
1,000 Lumen (100 Watt)	37	-	$ 4.29	$ -	-	$ 5.07	$ -	$ -	18.07%
2,500 Lumen (200 Watt)	71	-	$ 4.36	$ -	-	$ 5.15	$ -	$ -	18.07%
4,000 Lumen (325 Watt)	115	-	$ 4.58	$ -	-	$ 5.41	$ -	$ -	18.07%
6,000 Lumen (450 Watt)	158	-	$ 4.75	$ -	-	$ 5.61	$ -	$ -	18.07%
Company Distr. System									
1,000 Lumen (100 Watt)	37	10	$ 5.63	$ 56	10	$ 6.65	$ 66	$ 10	18.07%
2,500 Lumen (200 Watt)	71	-	$ 5.70	$ -	-	$ 6.73	$ -	$ -	18.07%
4,000 Lumen (325 Watt)	115	-	$ 5.92	$ -	-	$ 6.99	$ -	$ -	18.07%
6,000 Lumen (450 Watt)	158	-	$ 6.10	$ -	-	$ 7.20	$ -	$ -	18.07%

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Street & Area Lighting Rate Schedules

		Current			Pro Forma				
	kWh	Facility Counts	Rate	Revenue	Facility Counts	Rate	Revenue	Revenue Change	Percent Change
SCHEDULE EM									
(Equipment & Maintenance Service)									
Overhead Service									
MV Horizontal Cobra Head									
8,150 Lumen (175 Watt)		-	$ 8.76	$ -	-	$ 10.34	$ -	$ -	18.07%
HPS Horizontal Cobra Head									
9,500 Lumen (100 Watt)		2	$ 9.08	$ 18	2	$ 10.72	$ 21	$ 3	18.07%
22,000 Lumen (200 Watt)		-	$ 13.87	$ -	-	$ 16.38	$ -	$ -	18.07%
50,000 Lumen (400 Watt)		-	$ 15.89	$ -	-	$ 18.76	$ -	$ -	18.07%
MH Horizontal Cobra Head									
36,000 Lumen (400 Watt)		-	$ 16.67	$ -	-	$ 19.68	$ -	$ -	18.07%
90,000 Lumen (1,000 Watt)		-	$ 21.18	$ -	-	$ 25.01	$ -	$ -	18.07%
HPS Floodlight									
22,000 Lumen (200 Watt)		-	$ 15.62	$ -	-	$ 18.44	$ -	$ -	18.07%
50,000 Lumen (400 Watt)		1	$ 18.43	$ 17	1	$ 21.76	$ 20	$ 3	18.07%
MH Floodlight									
36,000 Lumen (400 Watt)		-	$ 19.66	$ -	-	$ 23.21	$ -	$ -	18.07%
90,000 Lumen (1000 Watt)		-	$ 22.94	$ -	-	$ 27.09	$ -	$ -	18.07%
Underground Service									
MH Colonial Post Top 14' Mounting Height									
11,600 Lumen (175 Watt)		4	$ 22.70	$ 91	4	$ 26.80	$ 107	$ 16	18.07%
HPS Horizontal Cobra Head/30' Mtg Height									
Single Luminaire Per Pole									
9,500 Lumen (100 Watt)		-	$ 24.60	$ -	-	$ 29.05	$ -	$ -	18.07%
22,000 Lumen (200 Watt)		-	$ 28.18	$ -	-	$ 33.27	$ -	$ -	18.07%
50,000 Lumen (400 Watt)		-	$ 31.44	$ -	-	$ 37.12	$ -	$ -	18.07%
Each Additional Luminaire Per Pole									
9,500 Lumen (100 Watt)		-	$ 9.08	$ -	-	$ 10.72	$ -	$ -	18.07%
22,000 Lumen (200 Watt)		-	$ 13.87	$ -	-	$ 16.38	$ -	$ -	18.07%
50,000 Lumen (400 Watt)		-	$ 15.89	$ -	-	$ 18.76	$ -	$ -	18.07%
MH Horizontal Cobra Head/30' Mtg Height									
Single Luminaire Per Pole									
36,500 Lumen (400 Watt)		-	$ 34.10	$ -	-	$ 40.26	$ -	$ -	18.07%
90,000 Lumen (1,000 Watt)		-	$ 42.11	$ -	-	$ 49.72	$ -	$ -	18.07%
Each Additional Luminaire Per Pole									
36,500 Lumen (400 Watt)		-	$ 16.67	$ -	-	$ 19.68	$ -	$ -	18.07%
90,000 Lumen (1,000 Watt)		-	$ 21.18	$ -	-	$ 25.01	$ -	$ -	18.07%
HPS Shoe Box/30' Mounting Height									
Single Luminaire Per Pole w/base									
9,500 Lumen (100 Watt)		1	$ 39.88	$ 40	1	$ 47.09	$ 47	$ 7	18.07%
22,000 Lumen (200 Watt)		-	$ 40.38	$ -	-	$ 47.68	$ -	$ -	18.07%
50,000 Lumen (400 Watt)		-	$ 40.44	$ -	-	$ 47.75	$ -	$ -	18.07%
No Base									
9,500 Lumen (100 Watt)		1	$ 36.83	$ 37	1	$ 43.49	$ 43	$ 7	18.07%
22,000 Lumen (200 Watt)		-	$ 37.60	$ -	-	$ 44.39	$ -	$ -	18.07%
50,000 Lumen (400 Watt)		-	$ 37.81	$ -	-	$ 44.64	$ -	$ -	18.07%
Each Additional Luminaire Per Pole									
9,500 Lumen (100 Watt)		-	$ 21.23	$ -	-	$ 25.07	$ -	$ -	18.07%
22,000 Lumen (200 Watt)		-	$ 22.01	$ -	-	$ 25.99	$ -	$ -	18.07%
50,000 Lumen (400 Watt)		-	$ 22.21	$ -	-	$ 26.22	$ -	$ -	18.07%
MH Shoe Box/30' Mounting Height									
With Base									
36,000 Lumen (400 Watt)		-	$ 41.45	$ -	-	$ 48.94	$ -	$ -	18.07%
No Base									
36,000 Lumen (400 Watt)		-	$ 38.82	$ -	-	$ 45.84	$ -	$ -	18.07%
Each Additional Luminaire Per Pole									
36,000 Lumen (400 Watt)		-	$ 23.22	$ -	-	$ 27.42	$ -	$ -	18.07%
MH Shoe Box/40' Mounting Height									
With Base									
90,000 Lumen (1,000 Watt)		-	$ 47.36	$ -	-	$ 55.92	$ -	$ -	18.07%
Each Additional Luminaire Per Pole									
90,000 Lumen (1,000 Watt)		-	$ 27.60	$ -	-	$ 32.59	$ -	$ -	18.07%

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Street & Area Lighting Rate Schedules

		Current			Pro Forma				
	kWh	Facility Counts	Rate	Revenue	Facility Counts	Rate	Revenue	Revenue Change	Percent Change
SCHEDULE EM - Long Term Service									
(Equipment & Maintenance Service)									
Overhead Service									
MV Horizontal Cobra Head									
8,150 Lumen (175 Watt)		-	$ 8.26	$ -	-	$ 9.84	$ -	$ -	19.16%
HPS Horizontal Cobra Head									
9,500 Lumen (100 Watt)		4	$ 8.58	$ 36	4	$ 10.22	$ 43	$ 7	19.12%
22,000 Lumen (200 Watt)		-	$ 13.37	$ -	-	$ 15.88	$ -	$ -	18.75%
50,000 Lumen (400 Watt)		-	$ 15.39	$ -	-	$ 18.26	$ -	$ -	18.66%
MH Horizontal Cobra Head									
36,000 Lumen (400 Watt)		-	$ 16.17	$ -	-	$ 19.18	$ -	$ -	18.63%
90,000 Lumen (1,000 Watt)		1	$ 20.68	$ 17	1	$ 24.51	$ 20	$ 3	18.51%
HPS Floodlight									
22,000 Lumen (200 Watt)		-	$ 15.12	$ -	-	$ 17.94	$ -	$ -	18.67%
50,000 Lumen (400 Watt)		-	$ 17.93	$ -	-	$ 21.26	$ -	$ -	18.57%
MH Floodlight									
36,000 Lumen (400 Watt)		-	$ 19.16	$ -	-	$ 22.71	$ -	$ -	18.54%
90,000 Lumen (1000 Watt)		-	$ 22.44	$ -	-	$ 26.59	$ -	$ -	18.47%
Underground Service									
MH Colonial Post Top 14' Mounting Height									
11,600 Lumen (175 Watt)		6	$ 22.20	$ 133	6	$ 26.30	$ 158	$ 25	18.48%
HPS Horizontal Cobra Head/30' Mtg Height									
Single Luminaire Per Pole									
9,500 Lumen (100 Watt)		-	$ 24.10	$ -	-	$ 28.55	$ -	$ -	18.45%
22,000 Lumen (200 Watt)		-	$ 27.68	$ -	-	$ 32.77	$ -	$ -	18.40%
50,000 Lumen (400 Watt)		-	$ 30.94	$ -	-	$ 36.62	$ -	$ -	18.36%
Each Additional Luminaire Per Pole									
9,500 Lumen (100 Watt)		-	$ 8.58	$ -	-	$ 10.22	$ -	$ -	19.12%
22,000 Lumen (200 Watt)		-	$ 13.37	$ -	-	$ 15.88	$ -	$ -	18.75%
50,000 Lumen (400 Watt)		-	$ 15.39	$ -	-	$ 18.26	$ -	$ -	18.66%
MH Horizontal Cobra Head/30' Mtg Height									
Single Luminaire Per Pole									
36,500 Lumen (400 Watt)		-	$ 33.60	$ -	-	$ 39.76	$ -	$ -	18.34%
90,000 Lumen (1,000 Watt)		8	$ 41.61	$ 333	8	$ 49.22	$ 394	$ 61	18.29%
Each Additional Luminaire Per Pole									
36,500 Lumen (400 Watt)		-	$ 16.17	$ -	-	$ 19.18	$ -	$ -	18.63%
90,000 Lumen (1,000 Watt)		-	$ 20.68	$ -	-	$ 24.51	$ -	$ -	18.51%
HPS Shoe Box/30' Mounting Height									
Single Luminaire Per Pole w/Base									
9,500 Lumen (100 Watt)		-	$ 39.38	$ -	-	$ 46.59	$ -	$ -	18.30%
22,000 Lumen (200 Watt)		-	$ 39.88	$ -	-	$ 47.18	$ -	$ -	18.30%
50,000 Lumen (400 Watt)		-	$ 39.94	$ -	-	$ 47.25	$ -	$ -	18.30%
No Base									
9,500 Lumen (100 Watt)		-	$ 36.33	$ -	-	$ 42.99	$ -	$ -	18.32%
22,000 Lumen (200 Watt)		-	$ 37.10	$ -	-	$ 43.89	$ -	$ -	18.31%
50,000 Lumen (400 Watt)		-	$ 37.31	$ -	-	$ 44.14	$ -	$ -	18.31%
Each Additional Luminaire Per Pole									
9,500 Lumen (100 Watt)		-	$ 20.73	$ -	-	$ 24.57	$ -	$ -	18.51%
22,000 Lumen (200 Watt)		-	$ 21.51	$ -	-	$ 25.49	$ -	$ -	18.49%
50,000 Lumen (400 Watt)		-	$ 21.71	$ -	-	$ 25.72	$ -	$ -	18.49%
MH Shoe Box/30' Mounting Height									
With Base									
36,000 Lumen (400 Watt)		-	$ 40.95	$ -	-	$ 48.44	$ -	$ -	18.29%
No Base									
36,000 Lumen (400 Watt)		-	$ 38.32	$ -	-	$ 45.34	$ -	$ -	18.31%
Each Additional Luminaire Per Pole									
36,000 Lumen (400 Watt)		-	$ 22.72	$ -	-	$ 26.92	$ -	$ -	18.47%
MH Shoe Box/40' Mounting Height									
With Base									
90,000 Lumen (1,000 Watt)		-	$ 46.86	$ -	-	$ 55.42	$ -	$ -	18.26%
Each Additional Luminaire Per Pole									
90,000 Lumen (1,000 Watt)		-	$ 27.10	$ -	-	$ 32.09	$ -	$ -	18.40%

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Street & Area Lighting Rate Schedules

		Current			Pro Forma				
	kWh	Facility Counts	Rate	Revenue	Facility Counts	Rate	Revenue	Revenue Change	Percent Change
SCHEDULE OL									
(Outdoor Lighting Service)									
High Pressure Sodium									
9,500 Lumen (100 Watt)	51	451	$ 8.81	$ 3,973	451	$ 10.40	$ 4,691	$ 718	18.07%
22,000 Lumen (200 Watt)	86	47	$ 15.93	$ 749	47	$ 18.81	$ 884	$ 135	18.07%
Mercury Vapor									
8,150 Lumen (175 Watt)	74	2,001	$ 8.37	$ 16,748	2,001	$ 9.88	$ 19,775	$ 3,027	18.07%
21,500 Lumen (400 Watt)	162	109	$ 14.58	$ 1,583	109	$ 17.21	$ 1,869	$ 286	18.07%
Standard Wood Pole		320	$ 3.60	$ 1,152	320	$ 4.25	$ 1,360	$ 208	18.07%
Wire		54,944	$ 0.022	$ 1,209	54,944	$ 0.026	$ 1,427	$ 218	18.07%
Transformer Capacity		72	$ 3.60	$ 259	72	$ 4.25	$ 306	$ 47	18.07%
SCHEDULE AL									
(Area Lighting Service)									
Underground Service(Area Lighting)									
8,150 Lumen (175 Watt)	74	1	$ 14.03	$ 14	1	$ 16.57	$ 17	$ 3	18.07%
Floodlighting									
Mercury Vapor									
21,500 Lumen (400 Watt)	162	60	$ 17.73	$ 1,067	60	$ 20.93	$ 1,260	$ 193	18.07%
60,000 Lumen (1,000 Watt)	386	23	$ 22.43	$ 516	23	$ 26.48	$ 609	$ 93	18.07%
High Pressure Sodium									
50,000 Lumen (400 Watt)	167	81	$ 23.60	$ 1,911	81	$ 27.86	$ 2,257	$ 345	18.07%
Quartz Iodine (500 Watt)	176	-	$ 18.61	$ -	-	$ 21.97	$ -	$ -	18.07%
Poles - Wood Standard									
30 foot		4	$ 3.67	$ 15	4	$ 4.33	$ 17	$ 3	18.07%
35 foot		45	$ 5.13	$ 228	45	$ 6.06	$ 270	$ 41	18.07%
40 foot		8	$ 5.50	$ 43	8	$ 6.49	$ 51	$ 8	18.07%
Poles - Wood Other									
14 foot		-	$ 7.42	$ -	-	$ 8.76	$ -	$ -	18.07%
35 foot		1	$ 7.81	$ 8	1	$ 9.22	$ 9	$ 1	18.07%
Poles - Metal									
14 foot		1	$ 5.16	$ 5	1	$ 6.09	$ 6	$ 1	18.07%
30 foot		-	$ 15.40	$ -	-	$ 18.18	$ -	$ -	18.07%
Wire		11,421	$ 0.023	$ 263	11,421	$ 0.027	$ 310	$ 47	18.07%
Customer Owned Equipment									
Mercury Vapor									
250 Watt	103	6	$ 5.05	$ 30	6	$ 5.96	$ 36	$ 5	18.07%
400 Watt	162	12	$ 5.47	$ 66	12	$ 6.46	$ 78	$ 12	18.07%
1,000 Watt	386	4	$ 7.61	$ 30	4	$ 8.99	$ 36	$ 6	18.07%
High Pressure Sodium									
400 Watt Bracket	167	32	$ 6.77	$ 217	32	$ 7.99	$ 256	$ 39	18.07%
400 Watt Post Top	167	75	$ 6.77	$ 508	75	$ 7.99	$ 600	$ 92	18.07%

The Potomac Edison Company (Maryland)
Proposed Distribution Rates
Street & Area Lighting Rate Schedules

		Current			Pro Forma				
	kWh	Facility Counts	Rate	Revenue	Facility Counts	Rate	Revenue	Revenue Change	Percent Change
SCHEDULE MSL									
(Street & Highway Service)									
High Pressure Sodium									
Overhead Supply - Wood Pole									
5,800 Lumen (70 Watt)	37	95	$ 8.65	$ 822	95	$ 10.21	$ 970	$ 148	18.07%
9,500 Lumen (100 Watt)	51	3,560	$ 8.56	$ 30,469	3,560	$ 10.11	$ 35,975	$ 5,506	18.07%
22,000 Lumen (200 Watt)	86	298	$ 13.35	$ 3,975	298	$ 15.76	$ 4,693	$ 718	18.07%
50,000 Lumen (400 Watt)	167	61	$ 19.00	$ 1,151	61	$ 22.43	$ 1,359	$ 208	18.07%
Multiple Units									
5,800 Lumen (70 Watt)	37	-	$ 8.65	$ -	-	$ 10.21	$ -	$ -	18.07%
9,500 Lumen (100 Watt)	51	1	$ 8.56	$ 9	1	$ 10.11	$ 10	$ 2	18.07%
22,000 Lumen (200 Watt)	86	18	$ 13.35	$ 240	18	$ 15.76	$ 284	$ 43	18.07%
50,000 Lumen (400 Watt)	167	-	$ 19.00	$ -	-	$ 22.43	$ -	$ -	18.07%
Overhead Supply - Metal Pole									
50,000 Lumen (400 Watt)	167	1	$ 32.22	$ 32	1	$ 38.04	$ 38	$ 6	18.07%
Underground Supply - Standard Pole									
Low mount									
5,800 Lumen (70 Watt)	37	-	$ 15.79	$ -	-	$ 18.64	$ -	$ -	18.07%
9,500 Lumen (100 Watt)	51	4,431	$ 15.64	$ 69,301	4,431	$ 18.47	$ 81,824	$ 12,523	18.07%
High mount									
5,800 Lumen (70 Watt)	37	-	$ 23.87	$ -	-	$ 28.18	$ -	$ -	18.07%
9,500 Lumen (100 Watt)	51	4	$ 23.77	$ 95	4	$ 28.07	$ 112	$ 17	18.07%
22,000 Lumen (200 Watt)	86	733	$ 26.57	$ 19,476	733	$ 31.37	$ 22,995	$ 3,519	18.07%
50,000 Lumen (400 Watt)	167	2	$ 32.22	$ 64	2	$ 38.04	$ 76	$ 12	18.07%
High Pressure Sodium - Rectangular Enclosed									
Underground Supply - Standard Pole									
High mount									
9,500 Lumen (100 Watt)	51	19	$ 37.01	$ 703	19	$ 43.70	$ 830	$ 127	18.07%
22,000 Lumen (200 Watt)	86	40	$ 37.80	$ 1,512	40	$ 44.63	$ 1,785	$ 273	18.07%
50,000 Lumen (400 Watt)	167	-	$ 36.19	$ -	-	$ 42.73	$ -	$ -	18.07%
Multiple Units									
9,500 Lumen (100 Watt)	51	-	$ 20.16	$ -	-	$ 23.80	$ -	$ -	18.07%
22,000 Lumen (200 Watt)	86	-	$ 20.99	$ -	-	$ 24.78	$ -	$ -	18.07%
50,000 Lumen (400 Watt)	167	-	$ 19.37	$ -	-	$ 22.87	$ -	$ -	18.07%
Mercury Vapor									
Overhead Supply - Wood Pole									
4,000 Lumen (100 Watt)	45	6	$ 8.46	$ 51	6	$ 9.99	$ 60	$ 9	18.07%
8,150 Lumen (175 Watt)	74	712	$ 7.40	$ 5,269	712	$ 8.74	$ 6,222	$ 952	18.07%
11,500 Lumen (250 Watt)	103	1	$ 10.81	$ 11	1	$ 12.76	$ 13	$ 2	18.07%
21,500 Lumen (400 Watt)	162	73	$ 10.90	$ 793	73	$ 12.87	$ 936	$ 143	18.07%
Overhead Supply - Metal Pole									
21,500 Lumen (400 Watt)	162	-	$ 24.51	$ -	-	$ 28.94	$ -	$ -	18.07%
Multiple Units									
8,150 Lumen (175 Watt)	74	-	$ 6.93	$ -	-	$ 8.18	$ -	$ -	18.07%
21,500 Lumen (400 Watt)	162	2	$ 10.23	$ 20	2	$ 12.08	$ 24	$ 4	18.07%
Underground Supply									
Low Mount									
4,000 Lumen (100 Watt)	45	6	$ 12.20	$ 73	6	$ 14.40	$ 86	$ 13	18.07%
8,150 Lumen (175 Watt)	74	1,058	$ 13.97	$ 14,773	1,058	$ 16.49	$ 17,443	$ 2,670	18.07%
High Mount									
11,500 Lumen (250 Watt)	103	-	$ 24.73	$ -	-	$ 29.20	$ -	$ -	18.07%
21,500 Lumen (400 Watt)	162	24	$ 24.51	$ 588	24	$ 28.94	$ 695	$ 106	18.07%
Continuous Burn									
Overhead Supply - Wood Pole									
22,000 Lumen (200 Watt)	86	2	$ 21.36	$ 43	2	$ 25.22	$ 50	$ 8	18.07%
50,000 Lumen (400 Watt)	167	1	$ 30.40	$ 23	1	$ 35.89	$ 27	$ 4	18.07%
Overhead wire		1,575	$ 0.022	$ 35	1,575	$ 0.026	$ 41	$ 6	18.07%
Underground wire		-	$ 0.029	$ -	-	$ 0.034	$ -	$ -	18.07%
Customer Owned Equipment									
5,800 Lumen (70 Watt)	37	-	$ 3.07	$ -	-	$ 3.62	$ -	$ -	18.07%
9,500 Lumen (100 Watt)	51	261	$ 2.95	$ 770	261	$ 3.48	$ 909	$ 139	18.07%
22,000 Lumen (200 Watt)	86	157	$ 3.60	$ 565	157	$ 4.25	$ 667	$ 102	18.07%
50,000 Lumen (400 Watt)	167	-	$ 6.08	$ -	-	$ 7.18	$ -	$ -	18.07%

The Potomac Edison Company (Maryland)
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Street & Area Lighting Rate Schedules

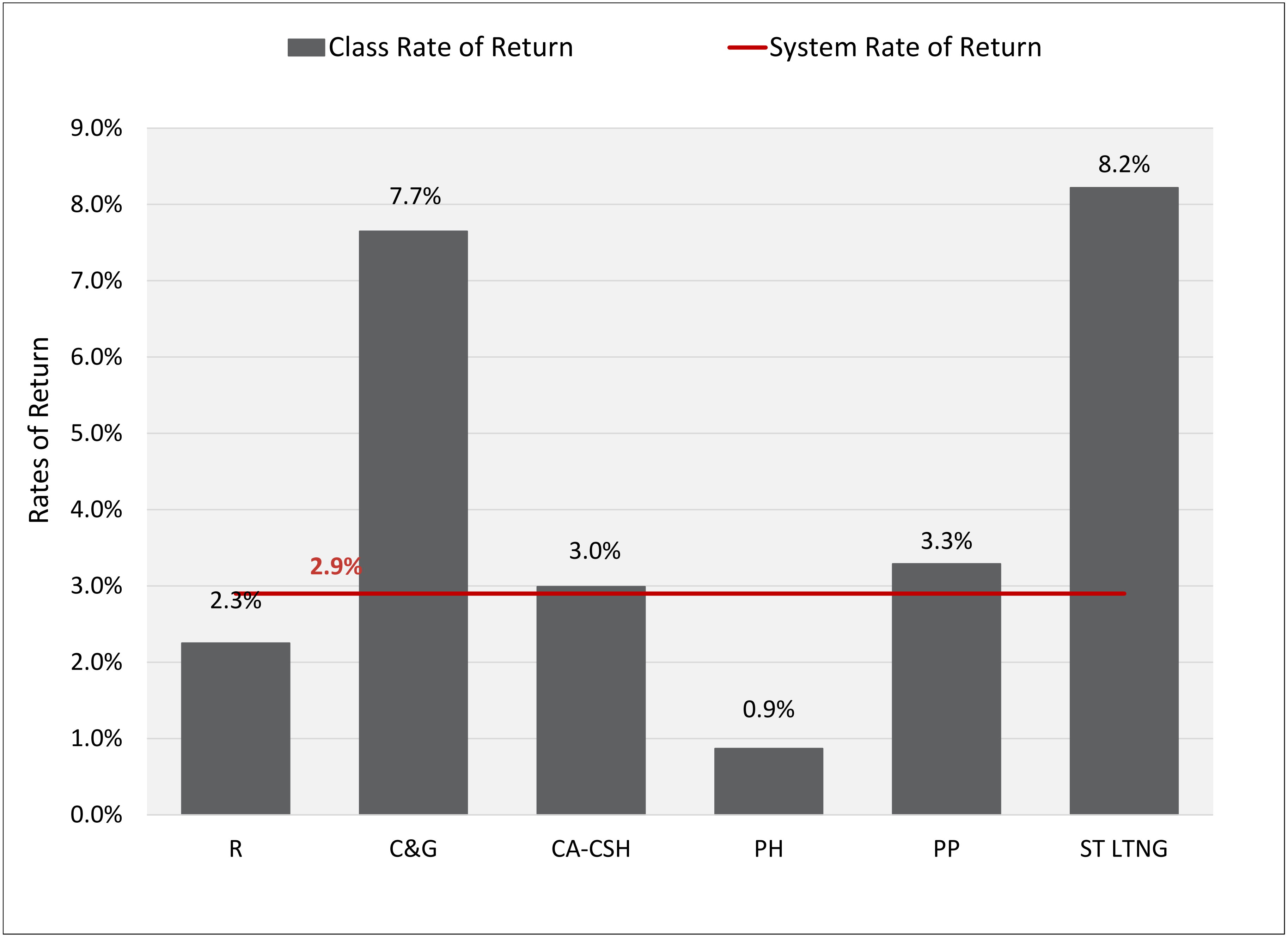
		Current			Pro Forma				
	kWh	Facility Counts	Rate	Revenue	Facility Counts	Rate	Revenue	Revenue Change	Percent Change
SCHEDULE LED									
(Light Emitting Diode Service)									
Short Term									
Cobra 4,000 Lumen (50 Watt)	18	6	$ 6.80	$ 41	6	$ 8.03	$ 48	$ 7	18.07%
Cobra 7,000 Lumen (90 Watt)	32	-	$ 8.55	$ -	-	$ 10.10	$ -	$ -	18.07%
Cobra 11,500 Lumen (130 Watt)	46	-	$ 9.10	$ -	-	$ 10.74	$ -	$ -	18.07%
Cobra 24,000 Lumen (260 Watt)	91	-	$ 14.16	$ -	-	$ 16.72	$ -	$ -	18.07%
Acorn 2,500 Lumen (50 Watt)	18	-	$ 18.27	$ -	-	$ 21.57	$ -	$ -	18.07%
Acorn 5,000 Lumen (90 Watt)	32	-	$ 19.30	$ -	-	$ 22.79	$ -	$ -	18.07%
Colonial 2,500 Lumen (50 Watt)	18	9	$ 10.93	$ 98	9	$ 12.91	$ 116	$ 18	18.07%
Colonial 5,000 Lumen (90 Watt)	32	-	$ 12.04	$ -	-	$ 14.22	$ -	$ -	18.07%
Long Term									
Cobra 4,000 Lumen (50 Watt)	18	487	$ 6.30	$ 3,068	487	$ 7.53	$ 3,667	$ 598	19.50%
Cobra 7,000 Lumen (90 Watt)	32	618	$ 8.05	$ 4,975	618	$ 9.60	$ 5,930	$ 955	19.19%
Cobra 11,500 Lumen (130 Watt)	46	108	$ 8.60	$ 929	108	$ 10.24	$ 1,106	$ 178	19.12%
Cobra 24,000 Lumen (260 Watt)	91	78	$ 13.66	$ 1,065	78	$ 16.22	$ 1,265	$ 200	18.73%
Acorn 2,500 Lumen (50 Watt)	18	-	$ 17.77	$ -	-	$ 21.07	$ -	$ -	18.58%
Acorn 5,000 Lumen (90 Watt)	32	-	$ 18.80	$ -	-	$ 22.29	$ -	$ -	18.55%
Colonial 2,500 Lumen (50 Watt)	18	573	$ 10.43	$ 5,976	573	$ 12.41	$ 7,108	$ 1,132	18.94%
Colonial 5,000 Lumen (90 Watt)	32	-	$ 11.54	$ -	-	$ 13.72	$ -	$ -	18.85%
Customer Owned Equipment	243,420		$ 0.03033	$ 7,383	243,420	$ 0.03581	$ 8,717	$ 1,334	18.07%
PE-CO-LED-260W-SB-with pole	91	82	$ 34.16	$ 2,801	91	$ 40.33	$ 3,670	$ 869	18.07%
PE-CO-LED-260W-SB-without pole	91	149	$ 16.60	$ 2,473	91	$ 19.60	$ 1,784	$ (690)	18.07%
Total - Monthly	1,949,263			$ 408,179			$ 482,199	$ 74,020	18.13%
Total - Annual	23,391,160			$ 4,898,153			$ 5,786,392	$ 888,240	18.13%
Franchise Tax Surcharge				$ 14,582			$ 14,582	$ -	0.00%
Montgomery County Energy Tax				$ 140,543			$ 140,543	$ -	0.00%
Unbilled	49,257			$ (2,486)			$ (2,935)	$ (449)	18.07%
TOTAL STREET & AREA LIGHTING				$ 5,050,792			$ 5,938,583	$ 887,791	17.58%
Per Books Revenue				$ 4,969,621			$ 5,843,144	$ 873,523	17.58%
Correction Factor				1.01633			1.01633		

Rate Schedule	Average Monthly Usage	Proposed Monthly Bill	Current Monthly Bill	Increase / (Decrease) ($)	Increase / (Decrease) (%)
Base Rates Only					
R	1,000	$ 33.24	$ 24.06	$ 9.18	38.2%
C	2,400	$ 72.32	$ 52.79	$ 19.53	37.0%
G	2,400	$ 64.90	$ 46.94	$ 17.96	38.3%
C-A	5,100	$ 126.17	$ 95.83	$ 30.34	31.7%
CSH	7,500	$ 142.18	$ 114.93	$ 27.25	23.7%
PH	89,200	$ 1,009.32	$ 784.40	$ 224.92	28.7%
PP	5,850,000	$ 10,459.40	$ 7,233.07	$ 3,226.33	44.6%
Total Rates					
R	1,000	$ 107.51	$ 98.33	$ 9.18	9.3%
C	2,400	$ 295.99	$ 276.46	$ 19.53	7.1%
G	2,400	$ 271.11	$ 253.15	$ 17.96	7.1%
C-A	5,100	$ 621.29	$ 590.95	$ 30.34	5.1%
CSH	7,500	$ 876.06	$ 848.81	$ 27.25	3.2%
PH	89,200	$ 8,373.42	$ 8,148.50	$ 224.92	2.8%
PP	5,850,000	$ 494,512.99	$ 491,286.66	$ 3,226.33	0.7%

The Potomac Edison Company (Maryland)
Summary of Rate Impact

Rate Schedule	Current Distribution Revenue*	Non-Distribution Revenue before EDIS Roll-In	Total	Proposed Distribution Revenue*	Non-Distribution Revenue after EDIS Roll-In	Low-Income Residential Program	Total	Distribution Revenue Increase	Total Revenue Increase	Estimated Total Bill % Change**
R	$ 83,434,046	$ 249,860,121	$ 333,294,167	$ 116,805,235	$ 246,974,932	$ 1,066,726	$ 364,846,893	$ 33,371,189	$ 31,552,726	9.47%
G	22,058,743	75,538,784	97,597,526	28,334,098	74,822,553	-	103,156,650	6,275,355	5,559,124	5.70%
C	2,590,310	8,957,899	11,548,209	3,376,516	8,884,882	-	12,261,399	786,206	713,189	6.18%
Hag & Fred	22,208	65,400	87,608	29,012	64,161	-	93,174	6,804	5,565	6.35%
C-A & CSH	435,542	2,385,754	2,821,296	569,506	2,357,298	-	2,926,805	133,964	105,508	3.74%
PH	19,356,146	151,511,208	170,867,354	24,997,563	150,467,345	-	175,464,908	5,641,417	4,597,554	2.69%
AGS	6,578	279,706	286,284	9,032	279,706	-	288,738	2,454	2,454	0.86%
PP	1,374,959	58,288,400	59,663,359	1,776,695	58,274,209	-	60,050,903	401,736	387,545	0.65%
Street Lighting	4,969,621	1,287,216	6,256,837	5,843,144	1,262,187	-	7,105,331	873,523	848,494	13.56%
Total	$ 134,248,154	$ 548,174,488	$ 682,422,642	$ 181,740,802	$ 543,387,274	$ 1,066,726	$ 726,194,802	$ 47,492,648	$ 43,772,160	6.41%

*Distribution plus tax surcharges for the Franchise Tax and the Montgomery County Fuel Energy Local Tax
**Includes Distribution, Surcharges and SOS (Transmission & Generation) as of March 2023


Class Rate of Return
System Rate of Return
Rates of Return
9.0%
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
2.3%
7.7%
3.0%
0.9%
3.3%
8.2%
2.9%
R
C&G
CA-CSH
PH
PP
ST LTNG

The Potomac Edison Company (Maryland) COSS Summary Alternative		Total Company		Residential Service R		Small C & I Schedule C&G		Small C & I Schedule CA-CSH		Medium Power Schedule PH		Large Power Schedule PP		Street and Area Lighting ST LTNG
Current Delivery Service Rates														
Rate base	$	718,525,219	$	458,185,599	$	94,965,517	$	2,485,237	$	133,759,198	$	7,494,295	$	21,635,372
Net operating income	$	20,838,731	$	10,312,671	$	7,265,095	$	74,331	$	1,161,788	$	246,570	$	1,778,276
Rate of return		2.90%		2.25%		7.65%		2.99%		0.87%		3.29%		8.22%
Relative rate of return		100%		78%		264%		103%		30%		113%		283%
Revenues	$	138,842,885	$	86,346,045	$	25,385,332	$	449,749	$	20,147,360	$	1,427,114	$	5,087,285
Test Period Usage (MWh)		6,819,525,904		3,354,870,600		905,734,700		23,300,136		1,802,643,017		709,586,291		23,391,160
Revenue per MWh	$	0.02	$	0.03	$	0.03	$	0.02	$	0.01	$	0.00	$	0.22
Revenues at Equalized Rates of Return														
Rate of return		7.54%		7.54%		7.54%		7.54%		7.54%		7.54%		7.54%
Return requirement	$	54,188,230	$	34,554,482	$	7,161,911	$	187,426	$	10,087,571	$	565,189	$	1,631,651
Revenue required	$	186,335,533	$	120,868,536	$	25,238,388	$	610,807	$	32,858,468	$	1,880,856	$	4,878,478
Revenue deficiency	$	47,492,648	$	34,522,491	$	(146,944)	$	161,058	$	12,711,108	$	453,742	$	(208,807)
Percent increase required		34.2%		40.0%		-0.6%		35.8%		63.1%		31.8%		-4.1%
Test Period Usage (MWh)		6,819,525,904		3,354,870,600		905,734,700		23,300,136		1,802,643,017		709,586,291		23,391,160
Revenue Required per MWh	$	0.03	$	0.04	$	0.03	$	0.03	$	0.02	$	0.00	$	0.21
Revenue Deficiency per MWh	$	0.01	$	0.01	$	(0.00)	$	0.01	$	0.01	$	0.00	$	(0.01)

Rate Class	Proposed Class ROR	Overall ROR	Alternative Class ROR
R	2.25%	2.90%	2.25%
C&G	7.65%	2.90%	7.65%
CA-CSH	2.99%	2.90%	2.99%
PH	0.87%	2.90%	0.87%
PP	3.29%	2.90%	3.29%
ST LTNG	8.22%	2.90%	8.22%

The Potomac Edison Company (Maryland) COSS Summary		Total Company		Residential Service R		Schedule C&G		Schedule CA-CSH		Schedule PH		Schedule PP		Area Lighting ST LTNG
Current Rate of Return		2.90%		2.25%		7.65%		2.99%		0.87%		3.29%		8.22%
Proposed Rate of Return		7.54%		7.54%		7.54%		7.54%		7.54%		7.54%		7.54%
EROR Revenues	$	186,335,533	$	120,868,536	$	25,238,388	$	610,807	$	32,858,468	$	1,880,856	$	4,878,478
Current Revenues		138,842,885		86,346,045		25,385,332		449,749		20,147,360		1,427,114		5,087,285
Difference	$	47,492,648	$	34,522,491	$	(146,944)	$	161,058	$	12,711,108	$	453,742	$	(208,807)
% Difference		34.21%		39.98%		-0.58%		35.81%		63.09%		31.79%		-4.10%
Derivation of Delivery Revenues														
Current Total Revenues	$	138,842,885		86,346,045		25,385,332		449,749		20,147,360		1,427,114		5,087,285
Less: Franchise Fees	$	4,256,657		2,108,602		564,626		14,498		1,117,658		436,690		14,582
Less: Montgomery County	$	9,797,215		4,686,975		1,784,838		38,374		3,146,485		-		140,543
Less: Other Revenues	$	4,594,731		2,911,999		714,071		14,207		784,635		52,156		117,663
Current Delivery Revenues	$	120,194,282	$	76,638,469	$	22,321,797	$	382,670	$	15,098,581	$	938,268	$	4,814,496
Total Revenues at EROR	$	186,335,533		120,868,536		25,238,388		610,807		32,858,468		1,880,856		4,878,478
Less: Franchise Fees	$	4,256,657		2,108,602		564,626		14,498		1,117,658		436,690		14,582
Less: Montgomery County	$	9,797,215		4,686,975		1,784,838		38,374		3,146,485		-		140,543
Less: Other Revenues	$	4,594,731		2,911,999		714,071		14,207		784,635		52,156		117,663
Delivery Revenues at EROR	$	167,686,930	$	111,160,960	$	22,174,853	$	543,728	$	27,809,689	$	1,392,010	$	4,605,689
Metrics														
Delivery Revenues at EROR		167,686,930		111,160,960		22,174,853		543,728		27,809,689		1,392,010		4,605,689
Test Period Usage (MWh)		6,819,525,904		3,354,870,600		905,734,700		23,300,136		1,802,643,017		709,586,291		23,391,160
Test Period Customers		284,640		250,592		31,222		325		1,682		10		809

The Potomac Edison Company (Maryland) Income Statement Current Rates	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
Going-Level Income Statement							
Operating Revenues	**$ 138,842,885**	**$ 86,346,045**	**$ 25,385,332**	**$ 449,749**	**$ 20,147,360**	**$ 1,427,114**	**$ 5,087,285**
Operating Expenses							
O&M Expenses	$ 56,655,385	$ 39,506,884	$ 7,473,216	$ 164,745	$ 7,671,243	$ 603,054	$ 1,236,243
Depreciation & Amortization	33,822,024	21,534,672	4,499,826	115,207	6,383,131	337,560	951,628
Regulatory Debits and Credits	1,288,352	997,537	129,305	2,052	84,448	60,685	14,325
Taxes Other than Income	30,607,318	17,909,928	4,882,787	107,670	6,691,743	213,720	801,469
Total Operating Expenses	$ 122,373,079	$ 79,949,021	$ 16,985,134	$ 389,674	$ 20,830,566	$ 1,215,019	$ 3,003,665
Income Before Tax	$ 16,469,806	$ 6,397,024	$ 8,400,198	$ 60,075	$ (683,206)	$ 212,095	$ 2,083,620
Income Adjustments							
Adjustment to Income - MD	$ 8,141,525	5,191,647	1,076,043	28,160	1,515,610	84,917	245,148
Interest Expense	13,420,137	8,557,687	1,773,703	46,418	2,498,266	139,973	404,091
Schedule M Adjustments	31,522,110	20,100,863	4,166,191	109,029	5,868,092	328,779	949,156
Total Income Adjustments	$ 53,083,772	$ 33,850,196	$ 7,015,937	$ 183,606	$ 9,881,967	$ 553,669	$ 1,598,395
Adjusted Taxable Income	$ (36,613,966)	$ (27,453,172)	$ 1,384,261	$ (123,531)	$ (10,565,174)	$ (341,575)	$ 485,225
State Income Tax	$ (3,020,652)	$ (2,264,887)	$ 114,202	$ (10,191)	$ (871,627)	$ (28,180)	$ 40,031
Federal Income Tax	(7,054,596)	(5,289,540)	266,712	(23,801)	(2,035,645)	(65,813)	93,491
Deferred Taxes	8,298,486	5,291,738	1,096,788	28,703	1,544,829	86,554	249,874
Total Income Taxes	$ (1,776,762)	$ (2,262,689)	$ 1,477,702	$ (5,290)	$ (1,362,442)	$ (7,439)	$ 383,396
AFUDC	2,609,343	1,663,913	344,870	9,025	485,750	27,216	78,569
Interest on Customer Deposits	(17,180)	(10,955)	(2,271)	(59)	(3,198)	(179)	(517)
Total Operating Income	**$ 20,838,731**	**$ 10,312,671**	**$ 7,265,095**	**$ 74,331**	**$ 1,161,788**	**$ 246,570**	**$ 1,778,276**
Rate Base	**$ 718,525,219**	**$ 458,185,599**	**$ 94,965,517**	**$ 2,485,237**	**$ 133,759,198**	**$ 7,494,295**	**$ 21,635,372**
ROR @ Current Rates	2.90%	2.25%	7.65%	2.99%	0.87%	3.29%	8.22%
Rate Base %	100.00%	63.77%	13.22%	0.35%	18.62%	1.04%	3.01%
Pro-Forma Income Tax Increase Calculation							
Rate Base	718,525,219	458,185,599	94,965,517	2,485,237	133,759,198	7,494,295	21,635,372
Required ROR	7.54%	7.54%	7.54%	7.54%	7.54%	7.54%	7.54%
Required Income	54,188,230	34,554,482	7,161,911	187,426	10,087,571	565,189	1,631,651
Increase in Earnings Requested	33,349,500	24,241,811	(103,184)	113,096	8,925,783	318,619	(146,625)
Increase in Revenues Requested	47,492,648	34,522,491	(146,944)	161,058	12,711,108	453,742	(208,807)
Pro-Forma Uncollectible Expense	400,682	291,257	(1,240)	1,359	107,240	3,828	(1,762)
Pro-Forma Regulatory Assessment	131,697	95,731	(407)	447	35,248	1,258	(579)
Pro-Forma Maryland Gross Receipt Tax	949,853	690,450	(2,939)	3,221	254,222	9,075	(4,176)
State Taxable Income	46,010,416	33,445,054	(142,358)	156,032	12,314,398	439,580	(202,290)
State Income Tax Increase	**3,795,859**	**2,759,217**	**(11,745)**	**12,873**	**1,015,938**	**36,265**	**(16,689)**
Federal Taxable Income	42,214,557	30,685,837	(130,613)	143,159	11,298,460	403,315	(185,601)
Federal Income Tax Increase	**8,865,057**	**6,444,026**	**(27,429)**	**30,063**	**2,372,677**	**84,696**	**(38,976)**
Revenue Requirement Calculation							
Required Income	54,188,230	34,554,482	7,161,911	187,426	10,087,571	565,189	1,631,651
Add: Expenses							
Current Expenses	122,373,079	79,949,021	16,985,134	389,674	20,830,566	1,215,019	3,003,665
Proforma Expense Increase	1,482,232	1,077,437	(4,586)	5,027	396,710	14,161	(6,517)
Add: Taxes							
Current Taxes	(1,776,762)	(2,262,689)	1,477,702	(5,290)	(1,362,442)	(7,439)	383,396
Proforma Tax Increase	12,660,916	9,203,243	(39,173)	42,936	3,388,614	120,962	(55,665)
Less: Other Revenues	(2,592,163)	(1,652,958)	(342,599)	(8,966)	(482,552)	(27,037)	(78,052)
Revenue Requirement	**186,335,533**	**120,868,536**	**25,238,388**	**610,807**	**32,858,468**	**1,880,856**	**4,878,478**

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
UTILITY PLANT									
Distribution Plant									
(360) Land and Land Rights		22,832,423							
- Demand		22,832,423	14,336,498	3,057,381	86,132	5,123,853	98,194	130,365	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		22,832,423	14,336,498	3,057,381	86,132	5,123,853	98,194	130,365	
(361) Structures and Improvements		11,490,605							
- Demand		11,490,605	7,051,472	1,542,653	45,423	2,757,913	24,799	68,345	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		11,490,605	7,051,472	1,542,653	45,423	2,757,913	24,799	68,345	
(362) Station Equipment		190,214,295							
- Demand		190,214,295	116,743,761	25,505,973	750,704	45,638,656	448,509	1,126,692	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		190,214,295	116,743,761	25,505,973	750,704	45,638,656	448,509	1,126,692	
(362) Station Equipment - Capacitors		1,528,215							
- Demand		1,528,215	962,922	151,304	3,909	339,726	69,416	938	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,528,215	962,922	151,304	3,909	339,726	69,416	938	
(364) Poles, Towers & Fixtures		134,210,133							
- Demand		134,210,133	86,039,970	17,104,788	455,780	28,184,980	1,807,482	617,131	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		134,210,133	86,039,970	17,104,788	455,780	28,184,980	1,807,482	617,131	
(365) Overhead Conductors & Devices		245,148,184							
- Demand		245,148,184	156,665,789	29,928,350	793,618	52,036,659	4,780,938	942,829	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		245,148,184	156,665,789	29,928,350	793,618	52,036,659	4,780,938	942,829	
(366) Underground Conduit		70,132,572							
- Demand		70,132,572	44,988,805	8,987,118	239,504	14,697,227	890,704	329,214	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		70,132,572	44,988,805	8,987,118	239,504	14,697,227	890,704	329,214	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(367) Underground Conductors & Device		319,482,180							
- Demand		319,482,180	205,032,531	40,647,424	1,080,006	66,855,191	4,410,985	1,456,042	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		319,482,180	205,032,531	40,647,424	1,080,006	66,855,191	4,410,985	1,456,042	
(368) Line Transformers		207,846,214							
- Demand		207,846,214	134,586,123	29,019,500	776,097	42,158,392	738	1,305,365	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		207,846,214	134,586,123	29,019,500	776,097	42,158,392	738	1,305,365	
(368) Line Transformers - Capacitors		1,518,797							
- Demand		1,518,797	928,164	146,877	3,768	327,464	111,621	905	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,518,797	928,164	146,877	3,768	327,464	111,621	905	
(369) Services		73,051,113							
- Demand		-	-	-	-	-	-	-	
- Customer		73,051,113	64,524,857	8,030,589	83,427	412,241	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		73,051,113	64,524,857	8,030,589	83,427	412,241	-	-	
(370, 371) Meters and Installation		58,934,191							
- Demand		-	-	-	-	-	-	-	
- Customer		58,934,191	35,003,730	16,591,288	366,058	5,986,423	986,692	-	
- Commodity		-	-	-	-	-	-	-	
Total		58,934,191	35,003,730	16,591,288	366,058	5,986,423	986,692	-	
Street Lighting & Signal Systems		33,964,292							
- Demand		-	-	-	-	-	-	-	
- Customer		33,964,292	-	-	-	-	-	33,964,292	
- Commodity		-	-	-	-	-	-	-	
Total		33,964,292	-	-	-	-	-	33,964,292	
Total Distribution Plant		1,370,353,215							
- Demand		1,204,403,618	767,336,035	156,091,369	4,234,942	258,120,061	12,643,385	5,977,826	
- Customer		165,949,597	99,528,588	24,621,876	449,485	6,398,664	986,692	33,964,292	
- Commodity		-	-	-	-	-	-	-	
Total		1,370,353,215	866,864,623	180,713,245	4,684,427	264,518,725	13,630,077	39,942,118	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
General and Intangible Plant									
General Plant		58,345,763							
- Demand		34,468,423	21,831,681	4,349,697	118,734	7,530,148	482,442	155,720	
- Customer		23,877,340	17,203,736	4,021,648	71,117	864,442	127,413	1,588,984	
- Commodity		-	-	-	-	-	-	-	
Total		58,345,763	39,035,418	8,371,345	189,851	8,394,590	609,855	1,744,704	
Intangible Plant		36,519,232							
- Demand		21,574,152	13,664,681	2,722,522	74,317	4,713,200	301,966	97,467	
- Customer		14,945,080	10,768,001	2,517,192	44,513	541,063	79,749	994,562	
- Commodity		-	-	-	-	-	-	-	
Total		36,519,232	24,432,682	5,239,714	118,830	5,254,263	381,715	1,092,029	
Total General and Intangible Plant		94,864,996							
- Demand		56,042,575	35,496,362	7,072,219	193,051	12,243,348	784,408	253,188	
- Customer		38,822,420	27,971,737	6,538,840	115,629	1,405,506	207,162	2,583,546	
- Commodity		-	-	-	-	-	-	-	
Total		94,864,996	63,468,100	13,611,059	308,681	13,648,854	991,570	2,836,734	
Additions to Utility Plant									
COVID-19 Regulatory Asset Adj excl. Res Adj		9,651,602							
- Demand		8,482,794	7,041,284	638,304	11,269	500,959	255,516	35,463	
- Customer		1,168,808	970,188	87,949	1,553	69,025	35,206	4,886	
- Commodity		-	-	-	-	-	-	-	
Total		9,651,602	8,011,472	726,253	12,821	569,984	290,722	40,349	
COVID-19 Residential Adjustment		(2,391,373)							
- Demand		(2,101,778)	(2,101,778)	-	-	-	-	-	
- Customer		(289,595)	(289,595)	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		(2,391,373)	(2,391,373)	-	-	-	-	-	
MD Electric Vehicle Program Reg Asset excl. Res Direct		670,401							
- Demand		589,216	-	211,106	5,721	347,571	16,701	8,117	
- Customer		81,186	-	30,095	549	7,821	1,206	41,514	
- Commodity		-	-	-	-	-	-	-	
Total		670,401	-	241,201	6,270	355,392	17,907	49,631	
MD EV Reg Asset - Residential Direct		855,889							
- Demand		752,241	752,241	-	-	-	-	-	
- Customer		103,648	103,648	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		855,889	855,889	-	-	-	-	-	
Total Additional to Utility Plant		8,786,519							
- Demand		7,722,473	5,691,747	849,410	16,989	848,530	272,217	43,579	
- Customer		1,064,046	784,241	118,044	2,102	76,846	36,412	46,400	
- Commodity		-	-	-	-	-	-	-	
Total		8,786,519	6,475,988	967,454	19,091	925,376	308,629	89,980	
Total Utility Plant		1,474,004,730							
- Demand		1,268,168,666	808,524,144	164,012,998	4,444,983	271,211,939	13,700,010	6,274,593	
- Customer		205,836,063	128,284,566	31,278,760	567,216	7,881,016	1,230,267	36,594,238	
- Commodity		-	-	-	-	-	-	-	
Total		**1,474,004,730**	**936,808,710**	**195,291,758**	**5,012,199**	**279,092,955**	**14,930,276**	**42,868,831**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
Distribution Plant A/D		(524,692,906)							
- Demand		(461,152,663)	(293,804,378)	(59,765,638)	(1,621,512)	(98,831,282)	(4,841,011)	(2,288,843)	
- Customer		(63,540,243)	(38,108,382)	(9,427,441)	(172,103)	(2,449,977)	(377,793)	(13,004,547)	
- Commodity		-	-	-	-	-	-	-	
Total		(524,692,906)	(331,912,760)	(69,193,079)	(1,793,615)	(101,281,259)	(5,218,804)	(15,293,390)	
General Plant A/D		(27,506,237)							
- Demand		(16,249,623)	(10,292,220)	(2,050,600)	(55,976)	(3,549,976)	(227,440)	(73,412)	
- Customer		(11,256,615)	(8,110,444)	(1,895,946)	(33,527)	(407,528)	(60,067)	(749,103)	
- Commodity		-	-	-	-	-	-	-	
Total		(27,506,237)	(18,402,664)	(3,946,545)	(89,502)	(3,957,504)	(287,507)	(822,515)	
Intangible Plant A/D		(24,687,910)							
- Demand		(21,698,207)	(13,825,115)	(2,813,274)	(76,330)	(4,649,869)	(225,769)	(107,850)	
- Customer		(2,989,703)	(2,154,095)	(503,554)	(8,905)	(108,238)	(15,953)	(198,958)	
- Commodity		-	-	-	-	-	-	-	
Total		(24,687,910)	(15,979,210)	(3,316,828)	(85,234)	(4,758,107)	(241,722)	(306,809)	
COVID Reg Asset A/D		(726,023)							
- Demand		(638,102)	(493,951)	(63,830)	(1,127)	(50,096)	(25,552)	(3,546)	
- Customer		(87,921)	(68,059)	(8,795)	(155)	(6,903)	(3,521)	(489)	
- Commodity		-	-	-	-	-	-	-	
Total		(726,023)	(562,010)	(72,625)	(1,282)	(56,998)	(29,072)	(4,035)	
EV Reg Asset A/D		(152,629)							
- Demand		(134,146)	(75,224)	(21,111)	(572)	(34,757)	(1,670)	(812)	
- Customer		(18,483)	(10,365)	(3,009)	(55)	(782)	(121)	(4,151)	
- Commodity		-	-	-	-	-	-	-	
Total		(152,629)	(85,589)	(24,120)	(627)	(35,539)	(1,791)	(4,963)	
CWIP A/D		(162,583)							
- Demand		(142,894)	(91,126)	(18,502)	(501)	(30,533)	(1,521)	(710)	
- Customer		(19,689)	(12,271)	(2,992)	(54)	(754)	(118)	(3,500)	
- Commodity		-	-	-	-	-	-	-	
Total		(162,583)	(103,397)	(21,494)	(556)	(31,287)	(1,639)	(4,210)	
Total Accumulated Depreciation		(577,928,288)							
- Demand		(500,015,635)	(318,582,013)	(64,732,955)	(1,756,018)	(107,146,513)	(5,322,963)	(2,475,173)	
- Customer		(77,912,654)	(48,463,616)	(11,841,737)	(214,799)	(2,974,181)	(457,573)	(13,960,748)	
- Commodity		-	-	-	-	-	-	-	
Total Accumulated Depreciation		**(577,928,288)**	**(367,045,629)**	**(76,574,692)**	**(1,970,816)**	**(110,120,695)**	**(5,780,535)**	**(16,435,921)**	
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Construction Work in Progress		50,574,771							
- Demand		43,512,302	27,741,379	5,627,472	152,512	9,305,589	470,063	215,288	
- Customer		7,062,468	4,401,589	1,073,210	19,462	270,407	42,212	1,255,590	
- Commodity		-	-	-	-	-	-	-	
Total		50,574,771	32,142,967	6,700,681	171,974	9,575,995	512,275	1,470,878	
Plant Held for Future Use		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Prepayments		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Working Capital		16,435,549							
- Demand		14,140,422	9,015,262	1,828,789	49,563	3,024,086	152,759	69,963	
- Customer		2,295,128	1,430,407	348,767	6,325	87,875	13,718	408,036	
- Commodity		-	-	-	-	-	-	-	
Total		16,435,549	10,445,669	2,177,556	55,887	3,111,962	166,477	477,999	
ADIT		(225,475,241)							
- Demand		(193,988,954)	(123,678,149)	(25,088,705)	(679,939)	(41,486,690)	(2,095,660)	(959,811)	
- Customer		(31,486,287)	(19,623,406)	(4,784,643)	(86,766)	(1,205,542)	(188,191)	(5,597,740)	
- Commodity		-	-	-	-	-	-	-	
Total		(225,475,241)	(143,301,555)	(29,873,348)	(766,705)	(42,692,232)	(2,283,851)	(6,557,550)	
Customer Advances		(5,061,698)							
- Demand		(4,448,727)	(2,834,323)	(576,557)	(15,643)	(953,423)	(46,701)	(22,080)	
- Customer		(612,971)	(367,630)	(90,946)	(1,660)	(23,635)	(3,645)	(125,454)	
- Commodity		-	-	-	-	-	-	-	
Total		(5,061,698)	(3,201,953)	(667,504)	(17,303)	(977,057)	(50,346)	(147,535)	
Customer Deposits		(14,024,604)							
- Demand		(12,066,151)	(6,592,572)	(1,797,227)	-	(3,640,794)	-	(35,558)	
- Customer		(1,958,453)	(1,070,038)	(291,707)	-	(590,936)	-	(5,771)	
- Commodity		-	-	-	-	-	-	-	
Total		(14,024,604)	(7,662,611)	(2,088,934)	-	(4,231,730)	-	(41,330)	
Deferred Investment Tax Credit		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Total Other Rate Base Items		(177,551,223)							
- Demand		(152,851,107)	(96,348,403)	(20,006,229)	(493,507)	(33,751,232)	(1,519,540)	(732,197)	
- Customer		(24,700,115)	(15,229,079)	(3,745,320)	(62,640)	(1,461,831)	(135,906)	(4,065,340)	
- Commodity		-	-	-	-	-	-	-	
Total		(177,551,223)	(111,577,482)	(23,751,549)	(556,146)	(35,213,062)	(1,655,446)	(4,797,538)	
Total Rate Base		**718,525,219**							
- Demand		**615,301,924**	**393,593,728**	**79,273,814**	**2,195,459**	**130,314,194**	**6,857,508**	**3,067,222**	
- Customer		**103,223,294**	**64,591,871**	**15,691,703**	**289,778**	**3,445,004**	**636,788**	**18,568,150**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**718,525,219**	**458,185,599**	**94,965,517**	**2,485,237**	**133,759,198**	**7,494,295**	**21,635,372**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
OPERATIONS & MAINTENANCE EXPENSES									
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering		68,716							
- Demand		45,556	29,117	5,719	153	9,664	705	198	
- Customer		23,160	14,171	5,068	105	1,647	266	1,902	
- Commodity		-	-	-	-	-	-	-	
Total		68,716	43,288	10,787	258	11,311	972	2,100	
(581) Load Dispatching		116,085							
- Demand		116,085	71,237	15,588	459	27,864	247	691	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		116,085	71,237	15,588	459	27,864	247	691	
(582) Station Expenses		16,885							
- Demand		16,885	10,362	2,267	67	4,053	36	101	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		16,885	10,362	2,267	67	4,053	36	101	
(583) Overhead line expenses		1,298,766							
- Demand		1,072,208	685,211	130,898	3,471	227,593	20,910	4,124	
- Customer		226,558	200,115	24,906	259	1,279	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,298,766	885,326	155,804	3,730	228,872	20,910	4,124	
(584) Underground line expenses		1,434,107							
- Demand		1,359,930	872,687	173,247	4,606	284,655	18,505	6,231	
- Customer		74,177	65,519	8,154	85	419	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,434,107	938,206	181,401	4,690	285,073	18,505	6,231	
(585) Street lighting and signal system expenses		107,100							
- Demand		-	-	-	-	-	-	-	
- Customer		107,100	-	-	-	-	-	107,100	
- Commodity		-	-	-	-	-	-	-	
Total		107,100	-	-	-	-	-	107,100	
(586) Meter expenses		896,233							
- Demand		-	-	-	-	-	-	-	
- Customer		896,233	532,314	252,310	5,567	91,038	15,005	-	
- Commodity		-	-	-	-	-	-	-	
Total		896,233	532,314	252,310	5,567	91,038	15,005	-	
(588) Miscellaneous distribution expenses		4,440,902							
- Demand		2,944,140	1,881,756	369,580	9,874	624,573	45,564	12,793	
- Customer		1,496,762	915,856	327,537	6,784	106,438	17,222	122,926	
- Commodity		-	-	-	-	-	-	-	
Total		4,440,902	2,797,611	697,117	16,657	731,010	62,786	135,719	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(589) Rents		1,069,104							
- Demand		708,773	453,015	88,973	2,377	150,360	10,969	3,080	
- Customer		360,331	220,483	78,851	1,633	25,624	4,146	29,593	
- Commodity		-	-	-	-	-	-	-	
Total		1,069,104	673,498	167,824	4,010	175,984	15,115	32,673	
Total Dist. Operations Expenses		9,447,898							
- Demand		6,263,578	4,003,384	786,272	21,006	1,328,762	96,937	27,218	
- Customer		3,184,320	1,948,458	696,826	14,432	226,443	36,640	261,521	
- Commodity		-	-	-	-	-	-	-	
Total		9,447,898	5,951,842	1,483,098	35,438	1,555,205	133,577	288,739	
Maintenance Expense									
(590) Maintenance Supervision and Engineering		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
(591) Maintenance of Structures		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
(592) Maintenance of Station Equipment		2,539,262							
- Demand		2,539,262	1,558,244	340,973	10,041	609,494	5,397	15,114	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		2,539,262	1,558,244	340,973	10,041	609,494	5,397	15,114	
(593) Maintenance of Overhead Lines		19,221,152							
- Demand		15,868,201	10,140,823	1,937,233	51,370	3,368,282	309,465	61,028	
- Customer		3,352,951	2,961,607	368,594	3,829	18,921	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		19,221,152	13,102,430	2,305,826	55,199	3,387,203	309,465	61,028	
(594) Maintenance of underground lines		934,344							
- Demand		886,017	568,570	112,873	3,001	185,457	12,056	4,060	
- Customer		48,327	42,687	5,313	55	273	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		934,344	611,256	118,186	3,056	185,730	12,056	4,060	
(595) Maintenance of line transformers		103,981							
- Demand		103,981	67,330	14,518	388	21,091	0	653	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		103,981	67,330	14,518	388	21,091	0	653	
(596) Maintenance of street lighting and signal systems		465,742							
- Demand		-	-	-	-	-	-	-	
- Customer		465,742	-	-	-	-	-	465,742	
- Commodity		-	-	-	-	-	-	-	
Total		465,742	-	-	-	-	-	465,742	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(597) Maintenance of meters		914,278							
- Demand		-	-	-	-	-	-	-	
- Customer		914,278	543,032	257,390	5,679	92,871	15,307	-	
- Commodity		-	-	-	-	-	-	-	
Total		914,278	543,032	257,390	5,679	92,871	15,307	-	
(598) Maintenance of miscellaneous distribution plant		157,146							
- Demand		126,071	80,169	15,635	421	27,195	2,125	526	
- Customer		31,075	23,055	4,103	62	728	99	3,027	
- Commodity		-	-	-	-	-	-	-	
Total		157,146	103,225	19,738	483	27,924	2,224	3,553	
Total Dist. Maintenance Expenses		24,335,905							
- Demand		19,523,531	12,415,136	2,421,231	65,221	4,211,519	329,044	81,380	
- Customer		4,812,374	3,570,381	635,399	9,625	112,793	15,407	468,769	
- Commodity		-	-	-	-	-	-	-	
Total		24,335,905	15,985,517	3,056,630	74,846	4,324,312	344,450	550,149	
Total Distribution Expenses		33,783,804							
- Demand		25,787,110	16,418,520	3,207,503	86,227	5,540,281	425,981	108,598	
- Customer		7,996,694	5,518,839	1,332,225	24,057	339,236	52,046	730,290	
- Commodity		-	-	-	-	-	-	-	
Total		33,783,804	21,937,359	4,539,728	110,284	5,879,517	478,027	838,888	
Customer Accounts and Services									
Meter Reading & Billing		6,854,217							
- Demand		-	-	-	-	-	-	-	
- Customer		6,854,217	5,857,097	934,546	12,631	44,634	-	5,309	
- Commodity		-	-	-	-	-	-	-	
Total		6,854,217	5,857,097	934,546	12,631	44,634	-	5,309	
Other-Direct to Other		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Uncollectibles		1,132,614							
- Demand		-	-	-	-	-	-	-	
- Customer		1,132,614	1,131,744	330	6	259	275	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,132,614	1,131,744	330	6	259	275	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Misc. Cust Serv and Info Exp		2,381,813							
- Demand		-	-	-	-	-	-	-	
- Customer		2,381,813	2,178,507	182,913	2,013	6,213	-	12,167	
- Commodity		-	-	-	-	-	-	-	
Total		2,381,813	2,178,507	182,913	2,013	6,213	-	12,167	
Customer Rebates & Incentives		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Customer Assistance		233,396							
- Demand		-	-	-	-	-	-	-	
- Customer		233,396	233,396	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		233,396	233,396	-	-	-	-	-	
Sales Expense		1							
- Demand		-	-	-	-	-	-	-	
- Customer		1	1	0	0	0	-	0	
- Commodity		-	-	-	-	-	-	-	
Total		1	1	0	0	0	-	0	
All Other Cust Accts & Services		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Total Customer Accounts and Services		10,602,041							
- Demand		-	-	-	-	-	-	-	
- Customer		10,602,041	9,400,745	1,117,789	14,650	51,106	275	17,476	
- Commodity		-	-	-	-	-	-	-	
Total		10,602,041	9,400,745	1,117,789	14,650	51,106	275	17,476	
Administrative & General Expense									
Administrative and General Salaries		3,795,263							
- Demand		2,242,095	1,420,103	282,938	7,723	489,819	31,382	10,129	
- Customer		1,553,168	1,119,065	261,599	4,626	56,230	8,288	103,360	
- Commodity		-	-	-	-	-	-	-	
Total		3,795,263	2,539,168	544,537	12,349	546,050	39,670	113,489	
Outside Services		7,307,223							
- Demand		4,316,825	2,734,200	544,756	14,870	943,076	60,421	19,502	
- Customer		2,990,398	2,154,596	503,671	8,907	108,263	15,957	199,004	
- Commodity		-	-	-	-	-	-	-	
Total		7,307,223	4,888,795	1,048,427	23,777	1,051,338	76,378	218,507	
Employee Benefits (Acct. 926)		(2,265,273)							
- Demand		(1,338,236)	(847,615)	(168,877)	(4,610)	(292,358)	(18,731)	(6,046)	
- Customer		(927,037)	(667,935)	(156,140)	(2,761)	(33,562)	(4,947)	(61,692)	
- Commodity		-	-	-	-	-	-	-	
Total		(2,265,273)	(1,515,550)	(325,017)	(7,371)	(325,920)	(23,678)	(67,738)	
Regulatory Commission Expenses (Acct 928)		1,326,184							
- Demand		1,165,583	743,201	216,465	3,711	146,418	9,099	46,689	
- Customer		160,601	102,402	29,826	511	20,174	1,254	6,433	
- Commodity		-	-	-	-	-	-	-	
Total		1,326,184	845,604	246,291	4,222	166,593	10,353	53,122	
General Advertising Expense		45,306							
- Demand		26,322	16,759	3,274	88	5,655	435	111	
- Customer		18,984	15,229	2,501	40	398	53	763	
- Commodity		-	-	-	-	-	-	-	
Total		45,306	31,988	5,775	128	6,054	488	874	
All Other O&M		2,060,838							
- Demand		1,217,464	771,120	153,636	4,194	265,973	17,040	5,500	
- Customer		843,375	607,655	142,049	2,512	30,533	4,500	56,125	
- Commodity		-	-	-	-	-	-	-	
Total		2,060,838	1,378,775	295,685	6,706	296,506	21,541	61,625	
Total A&G Expense		12,269,540							
- Demand		7,630,052	4,837,767	1,032,193	25,977	1,558,584	99,646	75,885	
- Customer		4,639,488	3,331,013	783,506	13,834	182,037	25,106	303,993	
- Commodity		-	-	-	-	-	-	-	
Total		12,269,540	8,168,780	1,815,699	39,811	1,740,621	124,752	379,878	
Total O&M Expenses		56,655,385							
- Demand		33,417,162	21,256,287	4,239,696	112,203	7,098,865	525,627	184,484	
- Customer		23,238,223	18,250,596	3,233,520	52,541	572,378	77,427	1,051,760	
- Commodity		-	-	-	-	-	-	-	
Total		**56,655,385**	**39,506,884**	**7,473,216**	**164,745**	**7,671,243**	**603,054**	**1,236,243**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
DEPRECIATION EXPENSE									
Depreciation Expense									
Distribution Plant DeprExp		28,696,459							
- Demand		25,221,322	16,068,724	3,268,697	88,684	5,405,272	264,764	125,181	
- Customer		3,475,137	2,084,220	515,605	9,413	133,994	20,662	711,244	
- Commodity		-	-	-	-	-	-	-	
Total		28,696,459	18,152,944	3,784,302	98,096	5,539,266	285,426	836,425	
General Plant DeprExp		2,947,291							
- Demand		1,741,146	1,102,811	219,722	5,998	380,380	24,370	7,866	
- Customer		1,206,145	869,034	203,150	3,592	43,667	6,436	80,266	
- Commodity		-	-	-	-	-	-	-	
Total		2,947,291	1,971,844	422,872	9,590	424,046	30,806	88,132	
Intangible Plant DeprExp		2,178,273							
- Demand		1,914,485	1,219,823	248,222	6,735	410,269	19,920	9,516	
- Customer		263,789	190,061	44,430	786	9,550	1,408	17,555	
- Commodity		-	-	-	-	-	-	-	
Total		2,178,273	1,409,884	292,652	7,520	419,819	21,328	27,070	
Total Depreciation Expenses		33,822,024							
- Demand		28,876,952	18,391,357	3,736,641	101,416	6,195,921	309,054	142,563	
- Customer		4,945,072	3,143,315	763,185	13,791	187,211	28,506	809,064	
- Commodity		-	-	-	-	-	-	-	
Total		**33,822,024**	**21,534,672**	**4,499,826**	**115,207**	**6,383,131**	**337,560**	**951,628**	
Regulatory Debits and Credits									
MD EDIS		(393,539)							
- Demand		(393,539)	(250,019)	(54,188)	(1,501)	(85,104)	(303)	(2,425)	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		(393,539)	(250,019)	(54,188)	(1,501)	(85,104)	(303)	(2,425)	
MD Electric Vehicle Program		305,258							
- Demand		262,631	147,274	41,263	1,119	68,074	3,319	1,582	
- Customer		42,627	23,904	6,941	127	1,804	278	9,574	
- Commodity		-	-	-	-	-	-	-	
Total		305,258	171,178	48,204	1,245	69,878	3,597	11,156	
MD Conservation Voltage Reduction (CVR)		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Deferral of Rate Case Expenses		(75,413)							
- Demand		(64,882)	(41,326)	(8,399)	(228)	(13,917)	(691)	(321)	
- Customer		(10,531)	(6,316)	(1,562)	(29)	(406)	(63)	(2,155)	
- Commodity		-	-	-	-	-	-	-	
Total		(75,413)	(47,642)	(9,961)	(256)	(14,323)	(754)	(2,476)	
COVID-19		1,930,321							
- Demand		1,696,559	1,408,257	127,661	2,254	100,192	51,103	7,093	
- Customer		233,762	194,038	17,590	311	13,805	7,041	977	
- Commodity		-	-	-	-	-	-	-	
Total		1,930,321	1,602,295	145,251	2,564	113,997	58,145	8,070	
COVID-19 - Residential Adjustment		(478,275)							
- Demand		(420,356)	(420,356)	-	-	-	-	-	
- Customer		(57,919)	(57,919)	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		(478,275)	(478,275)	-	-	-	-	-	
Total Regulatory Debits and Credits		1,288,352							
- Demand		1,080,413	843,830	106,337	1,644	69,245	53,428	5,929	
- Customer		207,939	153,707	22,968	409	15,203	7,257	8,396	
- Commodity		-	-	-	-	-	-	-	
Total		1,288,352	997,537	129,305	2,052	84,448	60,685	14,325	
Taxes Other than Income									
Distribution Payroll Taxes		621,313							
- Demand		445,037	281,879	56,161	1,533	97,225	6,229	2,011	
- Customer		176,276	109,245	33,995	676	10,306	1,645	20,409	
- Commodity		-	-	-	-	-	-	-	
Total		621,313	391,124	90,156	2,209	107,531	7,874	22,419	
Customer Account Payroll Taxes		228,896							
- Demand		-	-	-	-	-	-	-	
- Customer		228,896	195,719	31,088	420	1,483	-	186	
- Commodity		-	-	-	-	-	-	-	
Total		228,896	195,719	31,088	420	1,483	-	186	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Total	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
A&G Payroll Taxes		12,736							
- Demand		7,524	4,766	949	26	1,644	105	34	
- Customer		5,212	3,755	878	16	189	28	347	
- Commodity		-	-	-	-	-	-	-	
Total		12,736	8,521	1,827	41	1,832	133	381	
Gross Receipt Taxes		6,955,508							
- Demand		5,984,213	3,719,136	1,099,740	19,415	863,108	61,290	221,525	
- Customer		971,296	603,652	178,498	3,151	140,091	9,948	35,956	
- Commodity		-	-	-	-	-	-	-	
Total		6,955,508	4,322,787	1,278,239	22,566	1,003,199	71,238	257,480	
Property Taxes		13,480,260							
- Demand		11,597,821	7,394,220	1,499,953	40,651	2,480,323	125,291	57,383	
- Customer		1,882,439	1,173,205	286,055	5,187	72,074	11,251	334,666	
- Commodity		-	-	-	-	-	-	-	
Total		13,480,260	8,567,425	1,786,008	45,838	2,552,397	136,542	392,050	
Sales & Use Tax		(202,486)							
- Demand		(174,210)	(108,270)	(32,015)	(565)	(25,126)	(1,784)	(6,449)	
- Customer		(28,276)	(17,573)	(5,196)	(92)	(4,078)	(290)	(1,047)	
- Commodity		-	-	-	-	-	-	-	
Total		(202,486)	(125,843)	(37,211)	(657)	(29,205)	(2,074)	(7,496)	
Montgomery County Fuel Energy		9,510,444							
- Demand		8,182,366	3,914,433	1,490,648	32,049	2,627,858	-	117,378	
- Customer		1,328,077	635,350	241,947	5,202	426,527	-	19,052	
- Commodity		-	-	-	-	-	-	-	
Total		9,510,444	4,549,784	1,732,595	37,251	3,054,385	-	136,430	
Other Taxes		646							
- Demand		555	355	72	2	118	6	3	
- Customer		90	56	14	0	3	1	16	
- Commodity		-	-	-	-	-	-	-	
Total		646	412	85	2	121	7	19	
Total Taxes Other than Income		30,607,318							
- Demand		26,043,307	15,206,519	4,115,508	93,110	6,045,149	191,137	391,884	
- Customer		4,564,010	2,703,409	767,279	14,560	646,594	22,583	409,585	
- Commodity		-	-	-	-	-	-	-	
Total Taxes Other than Income		30,607,318	17,909,928	4,882,787	107,670	6,691,743	213,720	801,469	
Total Operating Expenses		**122,373,079**							
- Demand		**89,417,835**	**55,697,994**	**12,198,182**	**308,373**	**19,409,180**	**1,079,246**	**724,860**	
- Customer		**32,955,244**	**24,251,027**	**4,786,952**	**81,301**	**1,421,386**	**135,773**	**2,278,805**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**122,373,079**	**79,949,021**	**16,985,134**	**389,674**	**20,830,566**	**1,215,019**	**3,003,665**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
UTILITY PLANT									
Distribution Plant									
(360) Land and Land Rights		1,580,034							DEM
- Demand	12CP-SUB	1,580,034	995,572	156,434	4,042	351,246	71,769	970	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		1,580,034	995,572	156,434	4,042	351,246	71,769	970	
(361) Structures and Improvements		8,742							DEM
- Demand	12CP-SUB	8,742	5,508	866	22	1,943	397	5	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		8,742	5,508	866	22	1,943	397	5	
(362) Station Equipment		1,021,961							DEM
- Demand	12CP-SUB	1,021,961	643,933	101,181	2,614	227,185	46,420	628	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		1,021,961	643,933	101,181	2,614	227,185	46,420	628	
(362) Station Equipment - Capacitors		1,528,215							DEM
- Demand	12CP-SUB	1,528,215	962,922	151,304	3,909	339,726	69,416	938	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		1,528,215	962,922	151,304	3,909	339,726	69,416	938	
(364) Poles, Towers & Fixtures		39,543,103							DEM
- Demand	12CP-SUB	39,543,103	24,915,934	3,915,037	101,153	8,790,542	1,796,154	24,283	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		39,543,103	24,915,934	3,915,037	101,153	8,790,542	1,796,154	24,283	
(365) Overhead Conductors & Devices		104,904,585							DEM
- Demand	12CP-SUB	104,904,585	66,099,913	10,386,270	268,352	23,320,581	4,765,048	64,421	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		104,904,585	66,099,913	10,386,270	268,352	23,320,581	4,765,048	64,421	
(366) Underground Conduit		19,489,104							DEM
- Demand	12CP-SUB	19,489,104	12,279,998	1,929,554	49,854	4,332,482	885,247	11,968	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		19,489,104	12,279,998	1,929,554	49,854	4,332,482	885,247	11,968	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(367) Underground Conductors & Device		96,882,582							DEM
- Demand	12CP-SUB	96,882,582	61,045,285	9,592,037	247,831	21,537,267	4,400,667	59,495	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		96,882,582	61,045,285	9,592,037	247,831	21,537,267	4,400,667	59,495	
(368) Line Transformers		-							DEM
- Demand	12CP-SUB	-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(368) Line Transformers - Capacitors		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(369) Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(370, 371) Meters and Installation		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Street Lighting & Signal Systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Distribution Plant		264,958,327							
- Demand		264,958,327	166,949,066	26,232,684	677,778	58,900,973	12,035,118	162,709	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		264,958,327	166,949,066	26,232,684	677,778	58,900,973	12,035,118	162,709	
General and Intangible Plant									
General Plant		10,191,837							LABOR-SUB
- Demand	LABOR-SUB-D	10,191,837	6,421,832	1,009,062	26,071	2,265,674	462,941	6,259	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		10,191,837	6,421,832	1,009,062	26,071	2,265,674	462,941	6,259	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant		6,379,179							LABOR-SUB
- Demand	LABOR-SUB-D	6,379,179	4,019,493	631,582	16,318	1,418,109	289,759	3,917	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		6,379,179	4,019,493	631,582	16,318	1,418,109	289,759	3,917	
Total General and Intangible Plant		16,571,017							
- Demand		16,571,017	10,441,324	1,640,644	42,390	3,683,783	752,700	10,176	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		16,571,017	10,441,324	1,640,644	42,390	3,683,783	752,700	10,176	
Additions to Utility Plant									
COVID-19 Regulatory Asset Adj excl. Res Adj		1,866,141							DISTPLT-SUB
- Demand	COVID	1,866,141	1,549,021	140,421	2,479	110,207	56,211	7,801	100%
- Customer	COVID	-	-	-	-	-	-	-	0%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		1,866,141	1,549,021	140,421	2,479	110,207	56,211	7,801	
COVID-19 Residential Adjustment		(462,373)							DISTPLT-SUB
- Demand	Res-Direct	(462,373)	(462,373)	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(462,373)	(462,373)	-	-	-	-	-	
MD Electric Vehicle Program Reg Asset excl. Res Direct		129,622							DISTPLTxRES-SUB
- Demand	DISTPLTxRES-SUB-D	129,622	-	34,694	896	77,900	15,917	215	100%
- Customer	DISTPLTxRES-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLTxRES-SUB-E	-	-	-	-	-	-	-	0%
Total		129,622	-	34,694	896	77,900	15,917	215	
MD EV Reg Asset - Residential Direct		165,486							DISTPLT-SUB
- Demand	Res-Direct	165,486	165,486	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		165,486	165,486	-	-	-	-	-	
Total Additional to Utility Plant		1,698,877							
- Demand		1,698,877	1,252,135	175,115	3,375	188,106	72,128	8,017	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,698,877	1,252,135	175,115	3,375	188,106	72,128	8,017	
Total Utility Plant		283,228,221							
- Demand		283,228,221	178,642,524	28,048,443	723,543	62,772,862	12,859,946	180,902	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**283,228,221**	**178,642,524**	**28,048,443**	**723,543**	**62,772,862**	**12,859,946**	**180,902**	
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
Distribution Plant A/D		(101,449,577)							DISTPLT-SUB
- Demand	DISTPLT-SUB-D	(101,449,577)	(63,922,928)	(10,044,201)	(259,514)	(22,552,523)	(4,608,112)	(62,299)	100%
- Customer	DISTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		(101,449,577)	(63,922,928)	(10,044,201)	(259,514)	(22,552,523)	(4,608,112)	(62,299)	
General Plant A/D		(4,804,789)							LABOR-SUB
- Demand	LABOR-SUB-D	(4,804,789)	(3,027,476)	(475,707)	(12,291)	(1,068,118)	(218,246)	(2,951)	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		(4,804,789)	(3,027,476)	(475,707)	(12,291)	(1,068,118)	(218,246)	(2,951)	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant A/D		(4,773,417)							LABOR-SUB
- Demand	LABOR-SUB-D	(4,773,417)	(3,007,709)	(472,601)	(12,211)	(1,061,144)	(216,821)	(2,931)	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		(4,773,417)	(3,007,709)	(472,601)	(12,211)	(1,061,144)	(216,821)	(2,931)	
COVID Reg Asset A/D		(140,377)							COVIDREGASSET-SUB
- Demand	COVIDREGASSET-SUB-D	(140,377)	(108,665)	(14,042)	(248)	(11,021)	(5,621)	(780)	100%
- Customer	COVIDREGASSET-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	COVIDREGASSET-SUB-E	-	-	-	-	-	-	-	0%
Total		(140,377)	(108,665)	(14,042)	(248)	(11,021)	(5,621)	(780)	
EV Reg Asset A/D		(29,511)							EVREGASSET-SUB
- Demand	EVREGASSET-SUB-D	(29,511)	(16,549)	(3,469)	(90)	(7,790)	(1,592)	(22)	100%
- Customer	EVREGASSET-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	EVREGASSET-SUB-E	-	-	-	-	-	-	-	0%
Total		(29,511)	(16,549)	(3,469)	(90)	(7,790)	(1,592)	(22)	
CWIP A/D		(31,435)							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	(31,435)	(19,828)	(3,113)	(80)	(6,967)	(1,427)	(20)	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		(31,435)	(19,828)	(3,113)	(80)	(6,967)	(1,427)	(20)	
Total Accumulated Depreciation		(111,229,107)							
- Demand		(111,229,107)	(70,103,155)	(11,013,134)	(284,433)	(24,707,563)	(5,051,820)	(69,003)	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total Accumulated Depreciation		**(111,229,107)**	**(70,103,155)**	**(11,013,134)**	**(284,433)**	**(24,707,563)**	**(5,051,820)**	**(69,003)**	
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Construction Work in Progress		9,717,881							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	9,717,881	6,129,427	962,374	24,826	2,153,808	441,239	6,207	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		9,717,881	6,129,427	962,374	24,826	2,153,808	441,239	6,207	
Plant Held for Future Use		-							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Prepayments		-							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Working Capital		3,158,071							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	3,158,071	1,991,912	312,748	8,068	699,934	143,392	2,017	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		3,158,071	1,991,912	312,748	8,068	699,934	143,392	2,017	
ADIT		(43,324,794)							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	(43,324,794)	(27,326,552)	(4,290,508)	(110,679)	(9,602,226)	(1,967,158)	(27,672)	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		(43,324,794)	(27,326,552)	(4,290,508)	(110,679)	(9,602,226)	(1,967,158)	(27,672)	
Customer Advances		(978,681)							DISTPLT-SUB
- Demand	DISTPLT-SUB-D	(978,681)	(616,663)	(96,896)	(2,504)	(217,564)	(44,454)	(601)	100%
- Customer	DISTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		(978,681)	(616,663)	(96,896)	(2,504)	(217,564)	(44,454)	(601)	
Customer Deposits		(2,694,811)							TOTPLT-SUB
- Demand	Deposits	(2,694,811)	(1,472,361)	(401,386)	-	(813,122)	-	(7,941)	100%
- Customer	Deposits	-	-	-	-	-	-	-	0%
- Commodity	Deposits	-	-	-	-	-	-	-	0%
Total		(2,694,811)	(1,472,361)	(401,386)	-	(813,122)	-	(7,941)	
Deferred Investment Tax Credit		-							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Total Other Rate Base Items		(34,122,334)							
- Demand		(34,122,334)	(21,294,236)	(3,513,669)	(80,289)	(7,779,169)	(1,426,981)	(27,991)	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		(34,122,334)	(21,294,236)	(3,513,669)	(80,289)	(7,779,169)	(1,426,981)	(27,991)	
Total Rate Base		**137,876,780**							
- Demand		**137,876,780**	**87,245,134**	**13,521,641**	**358,821**	**30,286,130**	**6,381,146**	**83,908**	
- Customer		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**137,876,780**	**87,245,134**	**13,521,641**	**358,821**	**30,286,130**	**6,381,146**	**83,908**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
OPERATIONS & MAINTENANCE EXPENSES									
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering		15,362							DistOpExp-SUB
- Demand	DistOpExp-SUB-D	15,362	9,680	1,521	39	3,415	698	9	100%
- Customer	DistOpExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-SUB-E	-	-	-	-	-	-	-	0%
Total		15,362	9,680	1,521	39	3,415	698	9	
(581) Load Dispatching		-							DEM
- Demand		-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(582) Station Expenses		-							DEM
- Demand		-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(583) Overhead line expenses		458,823							OHLines-SUB
- Demand	OHLines-SUB-D	458,823	289,102	45,427	1,174	101,998	20,841	282	100%
- Customer	OHLines-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	OHLines-SUB-E	-	-	-	-	-	-	-	0%
Total		458,823	289,102	45,427	1,174	101,998	20,841	282	
(584) Underground line expenses		406,189							UGLines-SUB
- Demand	UGLines-SUB-D	406,189	255,938	40,216	1,039	90,297	18,450	249	100%
- Customer	UGLines-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	UGLines-SUB-E	-	-	-	-	-	-	-	0%
Total		406,189	255,938	40,216	1,039	90,297	18,450	249	
(585) Street lighting and signal system expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(586) Meter expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(588) Miscellaneous distribution expenses		992,830							DistOpExp-SUB
- Demand	DistOpExp-SUB-D	992,830	625,578	98,297	2,540	220,709	45,097	610	100%
- Customer	DistOpExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-SUB-E	-	-	-	-	-	-	-	0%
Total		992,830	625,578	98,297	2,540	220,709	45,097	610	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(589) Rents		239,014							DistOpExp-SUB
- Demand	DistOpExp-SUB-D	239,014	150,602	23,664	611	53,134	10,857	147	100%
- Customer	DistOpExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-SUB-E	-	-	-	-	-	-	-	0%
Total		239,014	150,602	23,664	611	53,134	10,857	147	
Total Dist. Operations Expenses		2,112,218							
- Demand		2,112,218	1,330,899	209,124	5,403	469,552	95,943	1,297	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		2,112,218	1,330,899	209,124	5,403	469,552	95,943	1,297	
Maintenance Expense									
(590) Maintenance Supervision and Engineering		-							DistMtExp-SUB
- Demand	DistMtExp-SUB-D	-	-	-	-	-	-	-	100%
- Customer	DistMtExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(591) Maintenance of Structures		-							DistMtExp-SUB
- Demand	DistMtExp-SUB-D	-	-	-	-	-	-	-	100%
- Customer	DistMtExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(592) Maintenance of Station Equipment		-							DEM
- Demand		-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(593) Maintenance of Overhead Lines		6,790,371							OHLines-SUB
- Demand	OHLines-SUB-D	6,790,371	4,278,582	672,293	17,370	1,509,518	308,437	4,170	100%
- Customer	OHLines-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	OHLines-SUB-E	-	-	-	-	-	-	-	0%
Total		6,790,371	4,278,582	672,293	17,370	1,509,518	308,437	4,170	
(594) Maintenance of underground lines		264,639							UGLines-SUB
- Demand	UGLines-SUB-D	264,639	166,748	26,201	677	58,830	12,021	163	100%
- Customer	UGLines-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	UGLines-SUB-E	-	-	-	-	-	-	-	0%
Total		264,639	166,748	26,201	677	58,830	12,021	163	
(595) Maintenance of line transformers		-							DEM
- Demand	12CP-SUB	-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(596) Maintenance of street lighting and signal systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(597) Maintenance of meters		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(598) Maintenance of miscellaneous distribution plant		45,853							DistMtExp-SUB
- Demand	DistMtExp-SUB-D	45,853	28,892	4,540	117	10,193	2,083	28	100%
- Customer	DistMtExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-SUB-E	-	-	-	-	-	-	-	0%
Total		45,853	28,892	4,540	117	10,193	2,083	28	
Total Dist. Maintenance Expenses		7,100,863							
- Demand		7,100,863	4,474,222	703,034	18,164	1,578,542	322,540	4,361	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		7,100,863	4,474,222	703,034	18,164	1,578,542	322,540	4,361	
Total Distribution Expenses		9,213,081							
- Demand		9,213,081	5,805,122	912,158	23,568	2,048,094	418,483	5,658	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		9,213,081	5,805,122	912,158	23,568	2,048,094	418,483	5,658	
Customer Accounts and Services									
Meter Reading & Billing		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Other-Direct to Other		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Uncollectibles		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Misc. Cust Serv and Info Exp		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Rebates & Incentives		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Assistance		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Sales Expense		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
All Other Cust Accts & Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Customer Accounts and Services		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Administrative & General Expense									
Administrative and General Salaries		662,957							NONAGLAB-SUB
- Demand	NONAGLAB-SUB-D	662,957	417,726	65,637	1,696	147,377	30,113	407	100%
- Customer	NONAGLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		662,957	417,726	65,637	1,696	147,377	30,113	407	
Outside Services		1,276,426							NONAGLAB-SUB
- Demand	NONAGLAB-SUB-D	1,276,426	804,270	126,375	3,265	283,753	57,979	784	100%
- Customer	NONAGLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		1,276,426	804,270	126,375	3,265	283,753	57,979	784	
Employee Benefits (Acct. 926)		(395,698)							NONAGLAB-SUB
- Demand	NONAGLAB-SUB-D	(395,698)	(249,328)	(39,177)	(1,012)	(87,965)	(17,974)	(243)	100%
- Customer	NONAGLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		(395,698)	(249,328)	(39,177)	(1,012)	(87,965)	(17,974)	(243)	
Regulatory Commission Expenses (Acct 928)		256,418							DISTPLT-SUB
- Demand	SalesREV	256,418	163,498	47,621	816	32,211	2,002	10,271	100%
- Customer	SalesREV	-	-	-	-	-	-	-	0%
- Commodity	SalesREV	-	-	-	-	-	-	-	0%
Total		256,418	163,498	47,621	816	32,211	2,002	10,271	
General Advertising Expense		9,404							OpExp-SUB
- Demand	OpExp-SUB-D	9,404	5,925	931	24	2,091	427	6	100%
- Customer	OpExp-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	OpExp-SUB-E	-	-	-	-	-	-	-	0%
Total		9,404	5,925	931	24	2,091	427	6	
All Other O&M		359,987							NONAGLAB-SUB
- Demand	NONAGLAB-SUB-D	359,987	226,826	35,641	921	80,026	16,352	221	100%
- Customer	NONAGLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		359,987	226,826	35,641	921	80,026	16,352	221	
Total A&G Expense		2,169,494							
- Demand		2,169,494	1,368,918	237,028	5,710	457,493	88,899	11,446	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		2,169,494	1,368,918	237,028	5,710	457,493	88,899	11,446	
Total O&M Expenses		11,382,575							
- Demand		11,382,575	7,174,040	1,149,186	29,278	2,505,586	507,382	17,104	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**11,382,575**	**7,174,040**	**1,149,186**	**29,278**	**2,505,586**	**507,382**	**17,104**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
DEPRECIATION EXPENSE									
Depreciation Expense									
Distribution Plant DeprExp		5,548,472							DISTPLT-SUB
- Demand	DISTPLT-SUB-D	5,548,472	3,496,067	549,337	14,193	1,233,441	252,026	3,407	100%
- Customer	DISTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		5,548,472	3,496,067	549,337	14,193	1,233,441	252,026	3,407	
General Plant DeprExp		514,833							LABOR-SUB
- Demand	LABOR-SUB-D	514,833	324,394	50,972	1,317	114,449	23,385	316	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		514,833	324,394	50,972	1,317	114,449	23,385	316	
Intangible Plant DeprExp		421,170							LABOR-SUB
- Demand	LABOR-SUB-D	421,170	265,377	41,699	1,077	93,627	19,131	259	100%
- Customer	LABOR-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SUB-E	-	-	-	-	-	-	-	0%
Total		421,170	265,377	41,699	1,077	93,627	19,131	259	
Total Depreciation Expenses		6,484,474							
- Demand		6,484,474	4,085,839	642,007	16,588	1,441,517	294,542	3,982	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**6,484,474**	**4,085,839**	**642,007**	**16,588**	**1,441,517**	**294,542**	**3,982**	
Regulatory Debits and Credits									
MD EDIS		(75,618)							DEM
- Demand	1NCP-PRI	(75,618)	(46,404)	(10,154)	(299)	(18,150)	(161)	(450)	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		(75,618)	(46,404)	(10,154)	(299)	(18,150)	(161)	(450)	
MD Electric Vehicle Program		58,655							EVREGASSET-SUB
- Demand	EVREGASSET-SUB-D	58,655	32,892	6,896	178	15,483	3,164	43	100%
- Customer	EVREGASSET-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	EVREGASSET-SUB-E	-	-	-	-	-	-	-	0%
Total		58,655	32,892	6,896	178	15,483	3,164	43	
MD Conservation Voltage Reduction (CVR)		-							DISTPLT-SUB
- Demand	DISTPLT-SUB-D	-	-	-	-	-	-	-	100%
- Customer	DISTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Deferral of Rate Case Expenses		(14,490)							DISTPLT-SUB
- Demand	DISTPLT-SUB-D	(14,490)	(9,130)	(1,435)	(37)	(3,221)	(658)	(9)	100%
- Customer	DISTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		(14,490)	(9,130)	(1,435)	(37)	(3,221)	(658)	(9)	
COVID-19		373,228							DISTPLT-SUB
- Demand	COVID	373,228	309,804	28,084	496	22,041	11,242	1,560	100%
- Customer	COVID	-	-	-	-	-	-	-	0%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		373,228	309,804	28,084	496	22,041	11,242	1,560	
COVID-19 - Residential Adjustment		(92,475)							DISTPLT-SUB
- Demand	Res-Direct	(92,475)	(92,475)	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(92,475)	(92,475)	-	-	-	-	-	
Total Regulatory Debits and Credits		249,300							
- Demand		249,300	194,687	23,391	338	16,153	13,587	1,144	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		249,300	194,687	23,391	338	16,153	13,587	1,144	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Sub-Transmission	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Taxes Other than Income									
Distribution Payroll Taxes		131,591							DISTLAB-SUB
- Demand	DISTLAB-SUB-D	131,591	82,915	13,028	337	29,253	5,977	81	100%
- Customer	DISTLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	DISTLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		131,591	82,915	13,028	337	29,253	5,977	81	
Customer Account Payroll Taxes		-							CUSTLAB-SUB
- Demand	CUSTLAB-SUB-D	-	-	-	-	-	-	-	0%
- Customer	CUSTLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	CUSTLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
A&G Payroll Taxes		2,225							AGLAB-SUB
- Demand	AGLAB-SUB-D	2,225	1,402	220	6	495	101	1	100%
- Customer	AGLAB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	AGLAB-SUB-E	-	-	-	-	-	-	-	0%
Total		2,225	1,402	220	6	495	101	1	
Gross Receipt Taxes		1,336,493							TOTPLT-SUB
- Demand	Revenue	1,336,493	830,618	245,612	4,336	192,763	13,688	49,475	100%
- Customer	Revenue	-	-	-	-	-	-	-	0%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		1,336,493	830,618	245,612	4,336	192,763	13,688	49,475	
Property Taxes		2,590,216							TOTPLT-SUB
- Demand	TOTPLT-SUB-D	2,590,216	1,633,745	256,512	6,617	574,079	117,608	1,654	100%
- Customer	TOTPLT-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SUB-E	-	-	-	-	-	-	-	0%
Total		2,590,216	1,633,745	256,512	6,617	574,079	117,608	1,654	
Sales & Use Tax		(38,907)							TOTPLT-SUB
- Demand	Revenue	(38,907)	(24,181)	(7,150)	(126)	(5,612)	(398)	(1,440)	100%
- Customer	Revenue	-	-	-	-	-	-	-	0%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		(38,907)	(24,181)	(7,150)	(126)	(5,612)	(398)	(1,440)	
Montgomery County Fuel Energy		1,827,420							TOTPLT-SUB
- Demand	MontCoFuel	1,827,420	874,235	332,916	7,158	586,896	-	26,215	100%
- Customer	MontCoFuel	-	-	-	-	-	-	-	0%
- Commodity	MontCoFuel	-	-	-	-	-	-	-	0%
Total		1,827,420	874,235	332,916	7,158	586,896	-	26,215	
Other Taxes		124							RB-SUB
- Demand	RB-SUB-D	124	78	12	0	27	6	0	100%
- Customer	RB-SUB-C	-	-	-	-	-	-	-	0%
- Commodity	RB-SUB-E	-	-	-	-	-	-	-	0%
Total		124	78	12	0	27	6	0	
Total Taxes Other than Income		5,849,161							
- Demand		5,849,161	3,398,814	841,151	18,327	1,377,902	136,982	75,986	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total Taxes Other than Income		5,849,161	3,398,814	841,151	18,327	1,377,902	136,982	75,986	
Total Operating Expenses		**23,965,511**							
- Demand		**23,965,511**	**14,853,379**	**2,655,736**	**64,530**	**5,341,157**	**952,493**	**98,215**	
- Customer		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**23,965,511**	**14,853,379**	**2,655,736**	**64,530**	**5,341,157**	**952,493**	**98,215**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
UTILITY PLANT									
Distribution Plant									
(360) Land and Land Rights		12,433,259							360P
- Demand	1NCP-PRI	12,433,259	7,629,798	1,669,541	49,163	2,984,331	26,424	74,002	100%
- Customer	Customers-PRI	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		12,433,259	7,629,798	1,669,541	49,163	2,984,331	26,424	74,002	
(361) Structures and Improvements		11,481,863							DEM
- Demand	1NCP-PRI	11,481,863	7,045,964	1,541,787	45,401	2,755,970	24,402	68,340	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		11,481,863	7,045,964	1,541,787	45,401	2,755,970	24,402	68,340	
(362) Station Equipment		189,192,334							DEM
- Demand	1NCP-PRI	189,192,334	116,099,828	25,404,792	748,090	45,411,471	402,088	1,126,064	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		189,192,334	116,099,828	25,404,792	748,090	45,411,471	402,088	1,126,064	
(362) Station Equipment - Capacitors		-							DEM
- Demand		-	-	-	-	-	-	-	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(364) Poles, Towers & Fixtures		5,330,296							364P
- Demand	1NCP-PRI	5,330,296	3,270,991	715,753	21,077	1,279,421	11,328	31,726	100%
- Customer	Customers-PRI	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		5,330,296	3,270,991	715,753	21,077	1,279,421	11,328	31,726	
(365) Overhead Conductors & Devices		7,476,890							365P
- Demand	1NCP-PRI	7,476,890	4,588,270	1,003,999	29,565	1,794,663	15,891	44,502	100%
- Customer	Customers-PRI	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		7,476,890	4,588,270	1,003,999	29,565	1,794,663	15,891	44,502	
(366) Underground Conduit		2,567,410							366P
- Demand	1NCP-PRI	2,567,410	1,575,517	344,752	10,152	616,250	5,456	15,281	100%
- Customer	Customers-PRI	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		2,567,410	1,575,517	344,752	10,152	616,250	5,456	15,281	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(367) Underground Conductors & Device		4,855,228							367P
- Demand	1NCP-PRI	4,855,228	2,979,461	651,961	19,198	1,165,391	10,319	28,898	100%
- Customer	Customers-PRI	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		4,855,228	2,979,461	651,961	19,198	1,165,391	10,319	28,898	
(368) Line Transformers		347,087							368P
- Demand	1NCP-PRI	347,087	212,993	46,607	1,372	83,311	738	2,066	100%
- Customer	Customers-PRI	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		347,087	212,993	46,607	1,372	83,311	738	2,066	
(368) Line Transformers - Capacitors		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(369) Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(370, 371) Meters and Installation		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Street Lighting & Signal Systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Distribution Plant		233,684,367							
- Demand		233,684,367	143,402,823	31,379,193	924,017	56,090,808	496,647	1,390,879	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		233,684,367	143,402,823	31,379,193	924,017	56,090,808	496,647	1,390,879	
General and Intangible Plant									
General Plant		9,175,889							LABOR-PRI
- Demand	LABOR-PRI-D	9,175,889	5,630,879	1,232,141	36,283	2,202,471	19,501	54,614	100%
- Customer	LABOR-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		9,175,889	5,630,879	1,232,141	36,283	2,202,471	19,501	54,614	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant		5,743,286							LABOR-PRI
- Demand	LABOR-PRI-D	5,743,286	3,524,427	771,210	22,710	1,378,550	12,206	34,184	100%
- Customer	LABOR-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		5,743,286	3,524,427	771,210	22,710	1,378,550	12,206	34,184	
Total General and Intangible Plant		14,919,176							
- Demand		14,919,176	9,155,306	2,003,351	58,992	3,581,021	31,708	88,798	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		14,919,176	9,155,306	2,003,351	58,992	3,581,021	31,708	88,798	
Additions to Utility Plant									
COVID-19 Regulatory Asset Adj excl. Res Adj		1,645,874							DISTPLT-PRI
- Demand	COVID	1,645,874	1,366,185	123,847	2,186	97,199	49,576	6,881	100%
- Customer	COVID	-	-	-	-	-	-	-	0%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		1,645,874	1,366,185	123,847	2,186	97,199	49,576	6,881	
COVID-19 Residential Adjustment		(407,797)							DISTPLT-PRI
- Demand	Res-Direct	(407,797)	(407,797)	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(407,797)	(407,797)	-	-	-	-	-	
MD Electric Vehicle Program Reg Asset excl. Res Direct		114,323							DISTPLTxRES-PRI
- Demand	DISTPLTxRES-PRI-D	114,323	-	39,735	1,170	71,027	629	1,761	100%
- Customer	DISTPLTxRES-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLTxRES-PRI-E	-	-	-	-	-	-	-	0%
Total		114,323	-	39,735	1,170	71,027	629	1,761	
MD EV Reg Asset - Residential Direct		145,953							DISTPLT-PRI
- Demand	Res-Direct	145,953	145,953	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		145,953	145,953	-	-	-	-	-	
Total Additional to Utility Plant		1,498,352							
- Demand		1,498,352	1,104,341	163,582	3,356	168,226	50,205	8,642	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,498,352	1,104,341	163,582	3,356	168,226	50,205	8,642	
Total Utility Plant		250,101,895							
- Demand		250,101,895	153,662,470	33,546,125	986,366	59,840,055	578,560	1,488,319	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**250,101,895**	**153,662,470**	**33,546,125**	**986,366**	**59,840,055**	**578,560**	**1,488,319**	
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
Distribution Plant A/D		(89,475,128)							DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(89,475,128)	(54,907,336)	(12,014,742)	(353,796)	(21,476,542)	(190,161)	(532,552)	100%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		(89,475,128)	(54,907,336)	(12,014,742)	(353,796)	(21,476,542)	(190,161)	(532,552)	
General Plant A/D		(4,325,836)							LABOR-PRI
- Demand	LABOR-PRI-D	(4,325,836)	(2,654,594)	(580,874)	(17,105)	(1,038,322)	(9,194)	(25,747)	100%
- Customer	LABOR-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		(4,325,836)	(2,654,594)	(580,874)	(17,105)	(1,038,322)	(9,194)	(25,747)	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant A/D		(4,209,994)							LABOR-PRI
- Demand	LABOR-PRI-D	(4,209,994)	(2,583,506)	(565,319)	(16,647)	(1,010,517)	(8,947)	(25,058)	100%
- Customer	LABOR-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		(4,209,994)	(2,583,506)	(565,319)	(16,647)	(1,010,517)	(8,947)	(25,058)	
COVID Reg Asset A/D		(123,808)							COVIDREGASSET-PRI
- Demand	COVIDREGASSET-PRI-D	(123,808)	(95,839)	(12,385)	(219)	(9,720)	(4,958)	(688)	100%
- Customer	COVIDREGASSET-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	COVIDREGASSET-PRI-E	-	-	-	-	-	-	-	0%
Total		(123,808)	(95,839)	(12,385)	(219)	(9,720)	(4,958)	(688)	
EV Reg Asset A/D		(26,028)							EVREGASSET-PRI
- Demand	EVREGASSET-PRI-D	(26,028)	(14,595)	(3,974)	(117)	(7,103)	(63)	(176)	100%
- Customer	EVREGASSET-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	EVREGASSET-PRI-E	-	-	-	-	-	-	-	0%
Total		(26,028)	(14,595)	(3,974)	(117)	(7,103)	(63)	(176)	
CWIP A/D		(27,725)							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	(27,725)	(17,034)	(3,719)	(109)	(6,634)	(64)	(165)	100%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		(27,725)	(17,034)	(3,719)	(109)	(6,634)	(64)	(165)	
Total Accumulated Depreciation		(98,188,518)							
- Demand		(98,188,518)	(60,272,904)	(13,181,012)	(387,993)	(23,548,837)	(213,386)	(584,386)	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total Accumulated Depreciation		**(98,188,518)**	**(60,272,904)**	**(13,181,012)**	**(387,993)**	**(23,548,837)**	**(213,386)**	**(584,386)**	
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Construction Work in Progress		8,581,279							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	8,581,279	5,272,333	1,151,006	33,843	2,053,180	19,851	51,066	100%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		8,581,279	5,272,333	1,151,006	33,843	2,053,180	19,851	51,066	
Plant Held for Future Use		-							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Prepayments		-							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Working Capital		2,788,703							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	2,788,703	1,713,378	374,048	10,998	667,233	6,451	16,595	100%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		2,788,703	1,713,378	374,048	10,998	667,233	6,451	16,595	
ADIT		(38,257,533)							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	(38,257,533)	(23,505,408)	(5,131,477)	(150,882)	(9,153,601)	(88,501)	(227,665)	100%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		(38,257,533)	(23,505,408)	(5,131,477)	(150,882)	(9,153,601)	(88,501)	(227,665)	
Customer Advances		(863,164)							DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(863,164)	(529,690)	(115,906)	(3,413)	(207,184)	(1,834)	(5,138)	100%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		(863,164)	(529,690)	(115,906)	(3,413)	(207,184)	(1,834)	(5,138)	
Customer Deposits		(2,379,626)							TOTPLT-PRI
- Demand	Deposits	(2,379,626)	(1,300,154)	(354,440)	-	(718,019)	-	(7,013)	100%
- Customer	Deposits	-	-	-	-	-	-	-	0%
- Commodity	Deposits	-	-	-	-	-	-	-	0%
Total		(2,379,626)	(1,300,154)	(354,440)	-	(718,019)	-	(7,013)	
Deferred Investment Tax Credit		-							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Total Other Rate Base Items		(30,130,341)							
- Demand		(30,130,341)	(18,349,540)	(4,076,769)	(109,454)	(7,358,391)	(64,033)	(172,154)	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		(30,130,341)	(18,349,540)	(4,076,769)	(109,454)	(7,358,391)	(64,033)	(172,154)	
Total Rate Base		**121,783,036**							
- Demand		**121,783,036**	**75,040,026**	**16,288,345**	**488,920**	**28,932,827**	**301,140**	**731,779**	
- Customer		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**121,783,036**	**75,040,026**	**16,288,345**	**488,920**	**28,932,827**	**301,140**	**731,779**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
OPERATIONS & MAINTENANCE EXPENSES									

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering		3,402							DistOpExp-PRI
- Demand	DistOpExp-PRI-D	3,402	2,088	457	13	817	7	20	100%
- Customer	DistOpExp-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-PRI-E	-	-	-	-	-	-	-	0%
Total		3,402	2,088	457	13	817	7	20	
(581) Load Dispatching		116,085							DEM
- Demand	1NCP-PRI	116,085	71,237	15,588	459	27,864	247	691	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		116,085	71,237	15,588	459	27,864	247	691	
(582) Station Expenses		16,885							DEM
- Demand	1NCP-PRI	16,885	10,362	2,267	67	4,053	36	101	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		16,885	10,362	2,267	67	4,053	36	101	
(583) Overhead line expenses		32,702							OHLines-PRI
- Demand	OHLines-PRI-D	32,702	20,068	4,391	129	7,849	70	195	100%
- Customer	OHLines-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	OHLines-PRI-E	-	-	-	-	-	-	-	0%
Total		32,702	20,068	4,391	129	7,849	70	195	
(584) Underground line expenses		25,908							UGLines-PRI
- Demand	UGLines-PRI-D	25,908	15,899	3,479	102	6,219	55	154	100%
- Customer	UGLines-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	UGLines-PRI-E	-	-	-	-	-	-	-	0%
Total		25,908	15,899	3,479	102	6,219	55	154	
(585) Street lighting and signal system expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(586) Meter expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(588) Miscellaneous distribution expenses		219,890							DistOpExp-PRI
- Demand	DistOpExp-PRI-D	219,890	134,938	29,527	869	52,780	467	1,309	100%
- Customer	DistOpExp-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-PRI-E	-	-	-	-	-	-	-	0%
Total		219,890	134,938	29,527	869	52,780	467	1,309	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(589) Rents		52,936							DistOpExp-PRI
- Demand	DistOpExp-PRI-D	52,936	32,485	7,108	209	12,706	113	315	100%
- Customer	DistOpExp-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-PRI-E	-	-	-	-	-	-	-	0%
Total		52,936	32,485	7,108	209	12,706	113	315	
Total Dist. Operations Expenses		467,809							
- Demand		467,809	287,076	62,818	1,850	112,287	994	2,784	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		467,809	287,076	62,818	1,850	112,287	994	2,784	
Maintenance Expense									
(590) Maintenance Supervision and Engineering		-							DistMtExp-PRI
- Demand	DistMtExp-PRI-D	-	-	-	-	-	-	-	100%
- Customer	DistMtExp-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(591) Maintenance of Structures		-							DistMtExp-PRI
- Demand	DistMtExp-PRI-D	-	-	-	-	-	-	-	100%
- Customer	DistMtExp-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(592) Maintenance of Station Equipment		2,539,262							DEM
- Demand	1NCP-PRI	2,539,262	1,558,244	340,973	10,041	609,494	5,397	15,114	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		2,539,262	1,558,244	340,973	10,041	609,494	5,397	15,114	
(593) Maintenance of Overhead Lines		483,972							OHLines-PRI
- Demand	OHLines-PRI-D	483,972	296,994	64,988	1,914	116,167	1,029	2,881	100%
- Customer	OHLines-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	OHLines-PRI-E	-	-	-	-	-	-	-	0%
Total		483,972	296,994	64,988	1,914	116,167	1,029	2,881	
(594) Maintenance of underground lines		16,880							UGLines-PRI
- Demand	UGLines-PRI-D	16,880	10,358	2,267	67	4,052	36	100	100%
- Customer	UGLines-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	UGLines-PRI-E	-	-	-	-	-	-	-	0%
Total		16,880	10,358	2,267	67	4,052	36	100	
(595) Maintenance of line transformers		174							368P
- Demand	1NCP-PRI	174	107	23	1	42	0	1	100%
- Customer	Customers-PRI	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		174	107	23	1	42	0	1	
(596) Maintenance of street lighting and signal systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(597) Maintenance of meters		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(598) Maintenance of miscellaneous distribution plant		19,760							DistMtExp-PRI
- Demand	DistMtExp-PRI-D	19,760	12,126	2,653	78	4,743	42	118	100%
- Customer	DistMtExp-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-PRI-E	-	-	-	-	-	-	-	0%
Total		19,760	12,126	2,653	78	4,743	42	118	
Total Dist. Maintenance Expenses		3,060,047							
- Demand		3,060,047	1,877,829	410,904	12,100	734,497	6,503	18,213	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		3,060,047	1,877,829	410,904	12,100	734,497	6,503	18,213	
Total Distribution Expenses		3,527,856							
- Demand		3,527,856	2,164,905	473,721	13,950	846,785	7,498	20,998	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		3,527,856	2,164,905	473,721	13,950	846,785	7,498	20,998	
Customer Accounts and Services									
Meter Reading & Billing		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Other-Direct to Other		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Uncollectibles		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Misc. Cust Serv and Info Exp		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Rebates & Incentives		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Assistance		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Sales Expense		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
All Other Cust Accts & Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Customer Accounts and Services		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Administrative & General Expense									
Administrative and General Salaries		596,871							NONAGLAB-PRI
- Demand	NONAGLAB-PRI-D	596,871	366,276	80,148	2,360	143,266	1,269	3,553	100%
- Customer	NONAGLAB-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		596,871	366,276	80,148	2,360	143,266	1,269	3,553	
Outside Services		1,149,188							NONAGLAB-PRI
- Demand	NONAGLAB-PRI-D	1,149,188	705,211	154,313	4,544	275,837	2,442	6,840	100%
- Customer	NONAGLAB-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		1,149,188	705,211	154,313	4,544	275,837	2,442	6,840	
Employee Benefits (Acct. 926)		(356,254)							NONAGLAB-PRI
- Demand	NONAGLAB-PRI-D	(356,254)	(218,619)	(47,838)	(1,409)	(85,511)	(757)	(2,120)	100%
- Customer	NONAGLAB-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		(356,254)	(218,619)	(47,838)	(1,409)	(85,511)	(757)	(2,120)	
Regulatory Commission Expenses (Acct 928)		226,152							DISTPLT-PRI
- Demand	SalesREV	226,152	144,200	42,000	720	28,409	1,765	9,059	100%
- Customer	SalesREV	-	-	-	-	-	-	-	0%
- Commodity	SalesREV	-	-	-	-	-	-	-	0%
Total		226,152	144,200	42,000	720	28,409	1,765	9,059	
General Advertising Expense		3,601							OpExp-PRI
- Demand	OpExp-PRI-D	3,601	2,210	484	14	864	8	21	100%
- Customer	OpExp-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	OpExp-PRI-E	-	-	-	-	-	-	-	0%
Total		3,601	2,210	484	14	864	8	21	
All Other O&M		324,103							NONAGLAB-PRI
- Demand	NONAGLAB-PRI-D	324,103	198,889	43,521	1,282	77,794	689	1,929	100%
- Customer	NONAGLAB-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		324,103	198,889	43,521	1,282	77,794	689	1,929	
Total A&G Expense		1,943,662							
- Demand		1,943,662	1,198,167	272,627	7,511	440,659	5,416	19,281	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		1,943,662	1,198,167	272,627	7,511	440,659	5,416	19,281	
Total O&M Expenses		5,471,518							
- Demand		5,471,518	3,363,072	746,349	21,461	1,287,444	12,913	40,279	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**5,471,518**	**3,363,072**	**746,349**	**21,461**	**1,287,444**	**12,913**	**40,279**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
DEPRECIATION EXPENSE									
Depreciation Expense									
Distribution Plant DeprExp		4,893,566							DISTPLT-PRI
- Demand	DISTPLT-PRI-D	4,893,566	3,002,987	657,109	19,350	1,174,593	10,400	29,126	100%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		4,893,566	3,002,987	657,109	19,350	1,174,593	10,400	29,126	
General Plant DeprExp		463,513							LABOR-PRI
- Demand	LABOR-PRI-D	463,513	284,440	62,241	1,833	111,256	985	2,759	100%
- Customer	LABOR-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		463,513	284,440	62,241	1,833	111,256	985	2,759	
Intangible Plant DeprExp		371,458							LABOR-PRI
- Demand	LABOR-PRI-D	371,458	227,949	49,879	1,469	89,160	789	2,211	100%
- Customer	LABOR-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-PRI-E	-	-	-	-	-	-	-	0%
Total		371,458	227,949	49,879	1,469	89,160	789	2,211	
Total Depreciation Expenses		5,728,537							
- Demand		5,728,537	3,515,376	769,229	22,651	1,375,010	12,175	34,096	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**5,728,537**	**3,515,376**	**769,229**	**22,651**	**1,375,010**	**12,175**	**34,096**	
Regulatory Debits and Credits									
MD EDIS		(66,774)							DEM
- Demand	1NCP-PRI	(66,774)	(40,976)	(8,966)	(264)	(16,028)	(142)	(397)	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		(66,774)	(40,976)	(8,966)	(264)	(16,028)	(142)	(397)	
MD Electric Vehicle Program		51,795							EVREGASSET-PRI
- Demand	EVREGASSET-PRI-D	51,795	29,045	7,907	233	14,134	125	350	100%
- Customer	EVREGASSET-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	EVREGASSET-PRI-E	-	-	-	-	-	-	-	0%
Total		51,795	29,045	7,907	233	14,134	125	350	
MD Conservation Voltage Reduction (CVR)		-							DISTPLT-PRI
- Demand	DISTPLT-PRI-D	-	-	-	-	-	-	-	100%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Deferral of Rate Case Expenses		(12,796)							DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(12,796)	(7,852)	(1,718)	(51)	(3,071)	(27)	(76)	100%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		(12,796)	(7,852)	(1,718)	(51)	(3,071)	(27)	(76)	
COVID-19		329,175							DISTPLT-PRI
- Demand	COVID	329,175	273,237	24,769	437	19,440	9,915	1,376	100%
- Customer	COVID	-	-	-	-	-	-	-	0%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		329,175	273,237	24,769	437	19,440	9,915	1,376	
COVID-19 - Residential Adjustment		(81,559)							DISTPLT-PRI
- Demand	Res-Direct	(81,559)	(81,559)	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(81,559)	(81,559)	-	-	-	-	-	
Total Regulatory Debits and Credits		219,841							
- Demand		219,841	171,894	21,992	355	14,475	9,871	1,253	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		219,841	171,894	21,992	355	14,475	9,871	1,253	
Taxes Other than Income									
Distribution Payroll Taxes		118,474							DISTLAB-PRI
- Demand	DISTLAB-PRI-D	118,474	72,703	15,909	468	28,437	252	705	100%
- Customer	DISTLAB-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	DISTLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		118,474	72,703	15,909	468	28,437	252	705	
Customer Account Payroll Taxes		-							CUSTLAB-PRI
- Demand	CUSTLAB-PRI-D	-	-	-	-	-	-	-	0%
- Customer	CUSTLAB-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	CUSTLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
A&G Payroll Taxes		2,003							AGLAB-PRI
- Demand	AGLAB-PRI-D	2,003	1,229	269	8	481	4	12	100%
- Customer	AGLAB-PRI-C	-	-	-	-	-	-	-	0%

The Potomac Edison Company (Maryland) Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
- Commodity	AGLAB-PRI-E	-	-	-	-	-	-	-	0%
Total		2,003	1,229	269	8	481	4	12	
Gross Receipt Taxes		1,180,177							TOTPLT-PRI
- Demand	Revenue	1,180,177	733,469	216,885	3,829	170,218	12,087	43,688	100%
- Customer	Revenue	-	-	-	-	-	-	-	0%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		1,180,177	733,469	216,885	3,829	170,218	12,087	43,688	
Property Taxes		2,287,264							TOTPLT-PRI
- Demand	TOTPLT-PRI-D	2,287,264	1,405,294	306,790	9,021	547,257	5,291	13,611	100%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-PRI-E	-	-	-	-	-	-	-	0%
Total		2,287,264	1,405,294	306,790	9,021	547,257	5,291	13,611	
Sales & Use Tax		(34,357)							TOTPLT-PRI
- Demand	Revenue	(34,357)	(21,352)	(6,314)	(111)	(4,955)	(352)	(1,272)	100%
- Customer	Revenue	-	-	-	-	-	-	-	0%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		(34,357)	(21,352)	(6,314)	(111)	(4,955)	(352)	(1,272)	
Montgomery County Fuel Energy		1,613,685							TOTPLT-PRI
- Demand	MontCoFuel	1,613,685	771,985	293,978	6,320	518,253	-	23,149	100%
- Customer	MontCoFuel	-	-	-	-	-	-	-	0%
- Commodity	MontCoFuel	-	-	-	-	-	-	-	0%
Total		1,613,685	771,985	293,978	6,320	518,253	-	23,149	
Other Taxes		110							RB-PRI
- Demand	RB-PRI-D	110	67	15	0	26	0	1	100%
- Customer	RB-PRI-C	-	-	-	-	-	-	-	0%
- Commodity	RB-PRI-E	-	-	-	-	-	-	-	0%
Total		110	67	15	0	26	0	1	
Total Taxes Other than Income		5,167,356							
- Demand		5,167,356	2,963,395	827,532	19,535	1,259,717	17,283	79,894	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total Taxes Other than Income		5,167,356	2,963,395	827,532	19,535	1,259,717	17,283	79,894	
Total Operating Expenses		**16,587,252**							
- Demand		**16,587,252**	**10,013,737**	**2,365,102**	**64,003**	**3,936,645**	**52,242**	**155,522**	
- Customer		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**16,587,252**	**10,013,737**	**2,365,102**	**64,003**	**3,936,645**	**52,242**	**155,522**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
UTILITY PLANT									
Distribution Plant									
(360) Land and Land Rights		8,819,130							360S
- Demand	1NCP-SEC	8,819,130	5,711,128	1,231,406	32,927	1,788,276	-	55,393	100%
- Customer	Customers-SEC	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		8,819,130	5,711,128	1,231,406	32,927	1,788,276	-	55,393	
(361) Structures and Improvements		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(362) Station Equipment		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(362) Station Equipment - Capacitors		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(364) Poles, Towers & Fixtures		89,336,733							364S
- Demand	1NCP-SEC	89,336,733	57,853,045	12,473,998	333,550	18,115,017	-	561,123	100%
- Customer	Customers-SEC	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		89,336,733	57,853,045	12,473,998	333,550	18,115,017	-	561,123	
(365) Overhead Conductors & Devices		132,766,709							365S
- Demand	1NCP-SEC	132,766,709	85,977,606	18,538,081	495,702	26,921,415	-	833,906	100%
- Customer	Customers-SEC	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		132,766,709	85,977,606	18,538,081	495,702	26,921,415	-	833,906	
(366) Underground Conduit		48,076,058							366S
- Demand	1NCP-SEC	48,076,058	31,133,289	6,712,811	179,498	9,748,494	-	301,965	100%
- Customer	Customers-SEC	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		48,076,058	31,133,289	6,712,811	179,498	9,748,494	-	301,965	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(367) Underground Conductors & Device		217,744,370							367S
- Demand	1NCP-SEC	217,744,370	141,007,785	30,403,426	812,977	44,152,533	-	1,367,649	100%
- Customer	Customers-SEC	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		217,744,370	141,007,785	30,403,426	812,977	44,152,533	-	1,367,649	
(368) Line Transformers		207,499,128							368S
- Demand	1NCP-SEC	207,499,128	134,373,129	28,972,893	774,725	42,075,082	-	1,303,299	100%
- Customer	Customers-SEC	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		207,499,128	134,373,129	28,972,893	774,725	42,075,082	-	1,303,299	
(368) Line Transformers - Capacitors		1,518,797							DEM
- Demand	12CP-GEN	1,518,797	928,164	146,877	3,768	327,464	111,621	905	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		1,518,797	928,164	146,877	3,768	327,464	111,621	905	
(369) Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(370, 371) Meters and Installation		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Street Lighting & Signal Systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Distribution Plant		705,760,924							
- Demand		705,760,924	456,984,146	98,479,492	2,633,147	143,128,280	111,621	4,424,238	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		705,760,924	456,984,146	98,479,492	2,633,147	143,128,280	111,621	4,424,238	
General and Intangible Plant									
General Plant		15,100,697							LABOR-SEC
- Demand	LABOR-SEC-D	15,100,697	9,778,971	2,108,495	56,380	3,062,003	-	94,847	100%
- Customer	LABOR-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		15,100,697	9,778,971	2,108,495	56,380	3,062,003	-	94,847	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant		9,451,686							LABOR-SEC
- Demand	LABOR-SEC-D	9,451,686	6,120,761	1,319,729	35,289	1,916,540	-	59,366	100%
- Customer	LABOR-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		9,451,686	6,120,761	1,319,729	35,289	1,916,540	-	59,366	
Total General and Intangible Plant		24,552,383							
- Demand		24,552,383	15,899,732	3,428,224	91,669	4,978,544	-	154,213	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		24,552,383	15,899,732	3,428,224	91,669	4,978,544	-	154,213	
Additions to Utility Plant									
COVID-19 Regulatory Asset Adj excl. Res Adj		4,970,779							DISTPLT-SEC
- Demand	COVID	4,970,779	4,126,078	374,036	6,603	293,554	149,728	20,781	100%
- Customer	COVID	-	-	-	-	-	-	-	0%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		4,970,779	4,126,078	374,036	6,603	293,554	149,728	20,781	
COVID-19 Residential Adjustment		(1,231,608)							DISTPLT-SEC
- Demand	Res-Direct	(1,231,608)	(1,231,608)	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(1,231,608)	(1,231,608)	-	-	-	-	-	
MD Electric Vehicle Program Reg Asset excl. Res Direct		345,271							DISTPLTxRES-SEC
- Demand	DISTPLTxRES-SEC-D	345,271	-	136,677	3,654	198,644	155	6,140	100%
- Customer	DISTPLTxRES-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLTxRES-SEC-E	-	-	-	-	-	-	-	0%
Total		345,271	-	136,677	3,654	198,644	155	6,140	
MD EV Reg Asset - Residential Direct		440,801							DISTPLT-SEC
- Demand	Res-Direct	440,801	440,801	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		440,801	440,801	-	-	-	-	-	
Total Additional to Utility Plant		4,525,243							
- Demand		4,525,243	3,335,271	510,713	10,258	492,198	149,883	26,921	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		4,525,243	3,335,271	510,713	10,258	492,198	149,883	26,921	
Total Utility Plant		734,838,550							
- Demand		734,838,550	476,219,149	102,418,429	2,735,074	148,599,022	261,504	4,605,372	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**734,838,550**	**476,219,149**	**102,418,429**	**2,735,074**	**148,599,022**	**261,504**	**4,605,372**	
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
Distribution Plant A/D		(270,227,957)							DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(270,227,957)	(174,974,114)	(37,706,695)	(1,008,203)	(54,802,216)	(42,738)	(1,693,991)	100%
- Customer	DISTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		(270,227,957)	(174,974,114)	(37,706,695)	(1,008,203)	(54,802,216)	(42,738)	(1,693,991)	
General Plant A/D		(7,118,998)							LABOR-SEC
- Demand	LABOR-SEC-D	(7,118,998)	(4,610,149)	(994,018)	(26,580)	(1,443,536)	-	(44,714)	100%
- Customer	LABOR-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		(7,118,998)	(4,610,149)	(994,018)	(26,580)	(1,443,536)	-	(44,714)	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant A/D		(12,714,796)							LABOR-SEC
- Demand	LABOR-SEC-D	(12,714,796)	(8,233,900)	(1,775,354)	(47,472)	(2,578,209)	-	(79,861)	100%
- Customer	LABOR-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		(12,714,796)	(8,233,900)	(1,775,354)	(47,472)	(2,578,209)	-	(79,861)	
COVID Reg Asset A/D		(373,917)							COVIDREGASSET-SEC
- Demand	COVIDREGASSET-SEC-D	(373,917)	(289,447)	(37,404)	(660)	(29,355)	(14,973)	(2,078)	100%
- Customer	COVIDREGASSET-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	COVIDREGASSET-SEC-E	-	-	-	-	-	-	-	0%
Total		(373,917)	(289,447)	(37,404)	(660)	(29,355)	(14,973)	(2,078)	
EV Reg Asset A/D		(78,607)							EVREGASSET-SEC
- Demand	EVREGASSET-SEC-D	(78,607)	(44,080)	(13,668)	(365)	(19,864)	(15)	(614)	100%
- Customer	EVREGASSET-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	EVREGASSET-SEC-E	-	-	-	-	-	-	-	0%
Total		(78,607)	(44,080)	(13,668)	(365)	(19,864)	(15)	(614)	
CWIP A/D		(83,734)							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	(83,734)	(54,264)	(11,670)	(312)	(16,933)	(30)	(525)	100%
- Customer	TOTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		(83,734)	(54,264)	(11,670)	(312)	(16,933)	(30)	(525)	
Total Accumulated Depreciation		(290,598,009)							
- Demand		(290,598,009)	(188,205,955)	(40,538,809)	(1,083,592)	(58,890,113)	(57,756)	(1,821,784)	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total Accumulated Depreciation		**(290,598,009)**	**(188,205,955)**	**(40,538,809)**	**(1,083,592)**	**(58,890,113)**	**(57,756)**	**(1,821,784)**	
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Construction Work in Progress		25,213,142							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	25,213,142	16,339,618	3,514,092	93,843	5,098,601	8,972	158,016	100%
- Customer	TOTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		25,213,142	16,339,618	3,514,092	93,843	5,098,601	8,972	158,016	
Plant Held for Future Use		-							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Prepayments		-							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Working Capital		8,193,648							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	8,193,648	5,309,972	1,141,993	30,497	1,656,919	2,916	51,351	100%
- Customer	TOTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		8,193,648	5,309,972	1,141,993	30,497	1,656,919	2,916	51,351	
ADIT		(112,406,627)							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	(112,406,627)	(72,846,189)	(15,666,720)	(418,378)	(22,730,864)	(40,002)	(704,474)	100%
- Customer	TOTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		(112,406,627)	(72,846,189)	(15,666,720)	(418,378)	(22,730,864)	(40,002)	(704,474)	
Customer Advances		(2,606,881)							DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(2,606,881)	(1,687,970)	(363,755)	(9,726)	(528,675)	(412)	(16,342)	100%
- Customer	DISTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		(2,606,881)	(1,687,970)	(363,755)	(9,726)	(528,675)	(412)	(16,342)	
Customer Deposits		(6,991,714)							TOTPLT-SEC
- Demand	Deposits	(6,991,714)	(3,820,057)	(1,041,401)	-	(2,109,653)	-	(20,604)	100%
- Customer	Deposits	-	-	-	-	-	-	-	0%
- Commodity	Deposits	-	-	-	-	-	-	-	0%
Total		(6,991,714)	(3,820,057)	(1,041,401)	-	(2,109,653)	-	(20,604)	
Deferred Investment Tax Credit		-							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	-	-	-	-	-	-	-	100%
- Customer	TOTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Total Other Rate Base Items		(88,598,432)							
- Demand		(88,598,432)	(56,704,627)	(12,415,791)	(303,764)	(18,613,672)	(28,526)	(532,053)	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		(88,598,432)	(56,704,627)	(12,415,791)	(303,764)	(18,613,672)	(28,526)	(532,053)	
Total Rate Base		**355,642,109**							
- Demand		**355,642,109**	**231,308,568**	**49,463,829**	**1,347,718**	**71,095,237**	**175,222**	**2,251,535**	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**355,642,109**	**231,308,568**	**49,463,829**	**1,347,718**	**71,095,237**	**175,222**	**2,251,535**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
OPERATIONS & MAINTENANCE EXPENSES									

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering		26,791							DistOpExp-SEC
- Demand	DistOpExp-SEC-D	26,791	17,349	3,741	100	5,432	-	168	100%
- Customer	DistOpExp-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-SEC-E	-	-	-	-	-	-	-	0%
Total		26,791	17,349	3,741	100	5,432	-	168	
(581) Load Dispatching		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(582) Station Expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(583) Overhead line expenses		580,684							OHLines-SEC
- Demand	OHLines-SEC-D	580,684	376,041	81,080	2,168	117,747	-	3,647	100%
- Customer	OHLines-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	OHLines-SEC-E	-	-	-	-	-	-	-	0%
Total		580,684	376,041	81,080	2,168	117,747	-	3,647	
(584) Underground line expenses		927,833							UGLines-SEC
- Demand	UGLines-SEC-D	927,833	600,850	129,552	3,464	188,139	-	5,828	100%
- Customer	UGLines-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	UGLines-SEC-E	-	-	-	-	-	-	-	0%
Total		927,833	600,850	129,552	3,464	188,139	-	5,828	
(585) Street lighting and signal system expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(586) Meter expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(588) Miscellaneous distribution expenses		1,731,421							DistOpExp-SEC
- Demand	DistOpExp-SEC-D	1,731,421	1,121,240	241,757	6,464	351,084	-	10,875	100%
- Customer	DistOpExp-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-SEC-E	-	-	-	-	-	-	-	0%
Total		1,731,421	1,121,240	241,757	6,464	351,084	-	10,875	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(589) Rents		416,823							DistOpExp-SEC
- Demand	DistOpExp-SEC-D	416,823	269,928	58,201	1,556	84,520	-	2,618	100%
- Customer	DistOpExp-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DistOpExp-SEC-E	-	-	-	-	-	-	-	0%
Total		416,823	269,928	58,201	1,556	84,520	-	2,618	
Total Dist. Operations Expenses		3,683,551							
- Demand		3,683,551	2,385,409	514,330	13,753	746,922	-	23,136	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		3,683,551	2,385,409	514,330	13,753	746,922	-	23,136	
Maintenance Expense									
(590) Maintenance Supervision and Engineering		-							DistMtExp-SEC
- Demand	DistMtExp-SEC-D	-	-	-	-	-	-	-	100%
- Customer	DistMtExp-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(591) Maintenance of Structures		-							DistMtExp-SEC
- Demand	DistMtExp-SEC-D	-	-	-	-	-	-	-	100%
- Customer	DistMtExp-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(592) Maintenance of Station Equipment		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(593) Maintenance of Overhead Lines		8,593,859							OHLines-SEC
- Demand	OHLines-SEC-D	8,593,859	5,565,246	1,199,952	32,086	1,742,597	-	53,978	100%
- Customer	OHLines-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	OHLines-SEC-E	-	-	-	-	-	-	-	0%
Total		8,593,859	5,565,246	1,199,952	32,086	1,742,597	-	53,978	
(594) Maintenance of underground lines		604,498							UGLines-SEC
- Demand	UGLines-SEC-D	604,498	391,463	84,405	2,257	122,575	-	3,797	100%
- Customer	UGLines-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	UGLines-SEC-E	-	-	-	-	-	-	-	0%
Total		604,498	391,463	84,405	2,257	122,575	-	3,797	
(595) Maintenance of line transformers		103,807							368S
- Demand	1NCP-SEC	103,807	67,224	14,494	388	21,049	-	652	100%
- Customer	Customers-SEC	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		103,807	67,224	14,494	388	21,049	-	652	
(596) Maintenance of street lighting and signal systems		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(597) Maintenance of meters		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(598) Maintenance of miscellaneous distribution plant		60,458							DistMtExp-SEC
- Demand	DistMtExp-SEC-D	60,458	39,152	8,442	226	12,259	-	380	100%
- Customer	DistMtExp-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DistMtExp-SEC-E	-	-	-	-	-	-	-	0%
Total		60,458	39,152	8,442	226	12,259	-	380	
Total Dist. Maintenance Expenses		9,362,622							
- Demand		9,362,622	6,063,085	1,307,293	34,957	1,898,481	-	58,806	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		9,362,622	6,063,085	1,307,293	34,957	1,898,481	-	58,806	
Total Distribution Expenses		13,046,172							
- Demand		13,046,172	8,448,493	1,821,624	48,710	2,645,403	-	81,943	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		13,046,172	8,448,493	1,821,624	48,710	2,645,403	-	81,943	
Customer Accounts and Services									
Meter Reading & Billing		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Other-Direct to Other		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Uncollectibles		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Misc. Cust Serv and Info Exp		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Rebates & Incentives		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Customer Assistance		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Sales Expense		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
All Other Cust Accts & Services		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
Total Customer Accounts and Services		-							
- Demand		-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	
Administrative & General Expense									
Administrative and General Salaries		982,267							NONAGLAB-SEC
- Demand	NONAGLAB-SEC-D	982,267	636,100	137,153	3,667	199,177	-	6,170	100%
- Customer	NONAGLAB-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		982,267	636,100	137,153	3,667	199,177	-	6,170	
Outside Services		1,891,211							NONAGLAB-SEC
- Demand	NONAGLAB-SEC-D	1,891,211	1,224,718	264,068	7,061	383,485	-	11,879	100%
- Customer	NONAGLAB-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		1,891,211	1,224,718	264,068	7,061	383,485	-	11,879	
Employee Benefits (Acct. 926)		(586,284)							NONAGLAB-SEC
- Demand	NONAGLAB-SEC-D	(586,284)	(379,668)	(81,862)	(2,189)	(118,882)	-	(3,682)	100%
- Customer	NONAGLAB-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		(586,284)	(379,668)	(81,862)	(2,189)	(118,882)	-	(3,682)	
Regulatory Commission Expenses (Acct 928)		683,013							DISTPLT-SEC
- Demand	SalesREV	683,013	435,504	126,845	2,175	85,799	5,332	27,359	100%
- Customer	SalesREV	-	-	-	-	-	-	-	0%
- Commodity	SalesREV	-	-	-	-	-	-	-	0%
Total		683,013	435,504	126,845	2,175	85,799	5,332	27,359	
General Advertising Expense		13,317							OpExp-SEC
- Demand	OpExp-SEC-D	13,317	8,624	1,859	50	2,700	-	84	100%
- Customer	OpExp-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	OpExp-SEC-E	-	-	-	-	-	-	-	0%
Total		13,317	8,624	1,859	50	2,700	-	84	
All Other O&M		533,374							NONAGLAB-SEC
- Demand	NONAGLAB-SEC-D	533,374	345,404	74,474	1,991	108,153	-	3,350	100%
- Customer	NONAGLAB-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	NONAGLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		533,374	345,404	74,474	1,991	108,153	-	3,350	
Total A&G Expense		3,516,897							
- Demand		3,516,897	2,270,682	522,538	12,755	660,432	5,332	45,158	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		3,516,897	2,270,682	522,538	12,755	660,432	5,332	45,158	
Total O&M Expenses		16,563,069							
- Demand		16,563,069	10,719,175	2,344,161	61,465	3,305,835	5,332	127,101	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**16,563,069**	**10,719,175**	**2,344,161**	**61,465**	**3,305,835**	**5,332**	**127,101**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
DEPRECIATION EXPENSE									
Depreciation Expense									
Distribution Plant DeprExp		14,779,284							DISTPLT-SEC
- Demand	DISTPLT-SEC-D	14,779,284	9,569,669	2,062,251	55,141	2,997,238	2,337	92,648	100%
- Customer	DISTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		14,779,284	9,569,669	2,062,251	55,141	2,997,238	2,337	92,648	
General Plant DeprExp		762,800							LABOR-SEC
- Demand	LABOR-SEC-D	762,800	493,977	106,509	2,848	154,675	-	4,791	100%
- Customer	LABOR-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		762,800	493,977	106,509	2,848	154,675	-	4,791	
Intangible Plant DeprExp		1,121,857							LABOR-SEC
- Demand	LABOR-SEC-D	1,121,857	726,497	156,644	4,189	227,482	-	7,046	100%
- Customer	LABOR-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	LABOR-SEC-E	-	-	-	-	-	-	-	0%
Total		1,121,857	726,497	156,644	4,189	227,482	-	7,046	
Total Depreciation Expenses		16,663,941							
- Demand		16,663,941	10,790,143	2,325,404	62,177	3,379,394	2,337	104,485	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**16,663,941**	**10,790,143**	**2,325,404**	**62,177**	**3,379,394**	**2,337**	**104,485**	
Regulatory Debits and Credits									
MD EDIS		(196,192)							DEM
- Demand	1NCP-SEC	(196,192)	(127,051)	(27,394)	(733)	(39,782)	-	(1,232)	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		(196,192)	(127,051)	(27,394)	(733)	(39,782)	-	(1,232)	
MD Electric Vehicle Program		152,181							EVREGASSET-SEC
- Demand	EVREGASSET-SEC-D	152,181	85,338	26,460	707	38,457	30	1,189	100%
- Customer	EVREGASSET-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	EVREGASSET-SEC-E	-	-	-	-	-	-	-	0%
Total		152,181	85,338	26,460	707	38,457	30	1,189	
MD Conservation Voltage Reduction (CVR)		-							DISTPLT-SEC
- Demand	DISTPLT-SEC-D	-	-	-	-	-	-	-	100%
- Customer	DISTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Deferral of Rate Case Expenses		(37,596)							DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(37,596)	(24,343)	(5,246)	(140)	(7,624)	(6)	(236)	100%
- Customer	DISTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		(37,596)	(24,343)	(5,246)	(140)	(7,624)	(6)	(236)	
COVID-19		994,156							DISTPLT-SEC
- Demand	COVID	994,156	825,216	74,807	1,321	58,711	29,946	4,156	100%
- Customer	COVID	-	-	-	-	-	-	-	0%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		994,156	825,216	74,807	1,321	58,711	29,946	4,156	
COVID-19 - Residential Adjustment		(246,322)							DISTPLT-SEC
- Demand	Res-Direct	(246,322)	(246,322)	-	-	-	-	-	100%
- Customer	Res-Direct	-	-	-	-	-	-	-	0%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(246,322)	(246,322)	-	-	-	-	-	
Total Regulatory Debits and Credits		666,228							
- Demand		666,228	512,838	68,627	1,155	49,761	29,970	3,877	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		666,228	512,838	68,627	1,155	49,761	29,970	3,877	
Taxes Other than Income									
Distribution Payroll Taxes		194,972							DISTLAB-SEC
- Demand	DISTLAB-SEC-D	194,972	126,261	27,224	728	39,535	-	1,225	100%
- Customer	DISTLAB-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	DISTLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		194,972	126,261	27,224	728	39,535	-	1,225	
Customer Account Payroll Taxes		-							CUSTLAB-SEC
- Demand	CUSTLAB-SEC-D	-	-	-	-	-	-	-	0%
- Customer	CUSTLAB-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	CUSTLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
A&G Payroll Taxes		3,296							AGLAB-SEC
- Demand	AGLAB-SEC-D	3,296	2,135	460	12	668	-	21	100%
- Customer	AGLAB-SEC-C	-	-	-	-	-	-	-	0%

The Potomac Edison Company (Maryland) Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
- Commodity	AGLAB-SEC-E	-	-	-	-	-	-	-	0%
Total		3,296	2,135	460	12	668	-	21	
Gross Receipt Taxes		3,467,544							TOTPLT-SEC
- Demand	Revenue	3,467,544	2,155,048	637,243	11,250	500,127	35,514	128,362	100%
- Customer	Revenue	-	-	-	-	-	-	-	0%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		3,467,544	2,155,048	637,243	11,250	500,127	35,514	128,362	
Property Taxes		6,720,341							TOTPLT-SEC
- Demand	TOTPLT-SEC-D	6,720,341	4,355,181	936,650	25,013	1,358,987	2,392	42,118	100%
- Customer	TOTPLT-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	TOTPLT-SEC-E	-	-	-	-	-	-	-	0%
Total		6,720,341	4,355,181	936,650	25,013	1,358,987	2,392	42,118	
Sales & Use Tax		(100,946)							TOTPLT-SEC
- Demand	Revenue	(100,946)	(62,737)	(18,551)	(327)	(14,559)	(1,034)	(3,737)	100%
- Customer	Revenue	-	-	-	-	-	-	-	0%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		(100,946)	(62,737)	(18,551)	(327)	(14,559)	(1,034)	(3,737)	
Montgomery County Fuel Energy		4,741,261							TOTPLT-SEC
- Demand	MontCoFuel	4,741,261	2,268,213	863,754	18,571	1,522,709	-	68,014	100%
- Customer	MontCoFuel	-	-	-	-	-	-	-	0%
- Commodity	MontCoFuel	-	-	-	-	-	-	-	0%
Total		4,741,261	2,268,213	863,754	18,571	1,522,709	-	68,014	
Other Taxes		322							RB-SEC
- Demand	RB-SEC-D	322	209	45	1	64	0	2	100%
- Customer	RB-SEC-C	-	-	-	-	-	-	-	0%
- Commodity	RB-SEC-E	-	-	-	-	-	-	-	0%
Total		322	209	45	1	64	0	2	
Total Taxes Other than Income		15,026,790							
- Demand		15,026,790	8,844,310	2,446,825	55,247	3,407,531	36,872	236,005	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total Taxes Other than Income		15,026,790	8,844,310	2,446,825	55,247	3,407,531	36,872	236,005	
Total Operating Expenses		**48,920,028**							
- Demand		**48,920,028**	**30,866,466**	**7,185,018**	**180,045**	**10,142,521**	**74,511**	**471,468**	
- Customer		-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	
Total		**48,920,028**	**30,866,466**	**7,185,018**	**180,045**	**10,142,521**	**74,511**	**471,468**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
UTILITY PLANT									
Distribution Plant									
(360) Land and Land Rights		-							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer		-	-	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(361) Structures and Improvements		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(362) Station Equipment		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(362) Station Equipment - Capacitors		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(364) Poles, Towers & Fixtures		-							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer		-	-	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(365) Overhead Conductors & Devices		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(366) Underground Conduit		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(367) Underground Conductors & Device		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(368) Line Transformers		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(368) Line Transformers - Capacitors		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(369) Services		73,051,113							369
- Demand	1NCPxLT-SEC	-	-	-	-	-	-	-	0%
- Customer	CUSxLT-SEC	73,051,113	64,524,857	8,030,589	83,427	412,241	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		73,051,113	64,524,857	8,030,589	83,427	412,241	-	-	
(370, 371) Meters and Installation		58,934,191							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Meters	58,934,191	35,003,730	16,591,288	366,058	5,986,423	986,692	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		58,934,191	35,003,730	16,591,288	366,058	5,986,423	986,692	-	
Street Lighting & Signal Systems		33,964,292							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	StreetLighting	33,964,292	-	-	-	-	-	33,964,292	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		33,964,292	-	-	-	-	-	33,964,292	
Total Distribution Plant		165,949,597							
- Demand		-	-	-	-	-	-	-	
- Customer		165,949,597	99,528,588	24,621,876	449,485	6,398,664	986,692	33,964,292	
- Commodity		-	-	-	-	-	-	-	
Total		165,949,597	99,528,588	24,621,876	449,485	6,398,664	986,692	33,964,292	
General and Intangible Plant									
General Plant		23,877,340							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	23,877,340	17,203,736	4,021,648	71,117	864,442	127,413	1,588,984	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		23,877,340	17,203,736	4,021,648	71,117	864,442	127,413	1,588,984	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant		14,945,080							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	14,945,080	10,768,001	2,517,192	44,513	541,063	79,749	994,562	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		14,945,080	10,768,001	2,517,192	44,513	541,063	79,749	994,562	
Total General and Intangible Plant		38,822,420							
- Demand		-	-	-	-	-	-	-	
- Customer		38,822,420	27,971,737	6,538,840	115,629	1,405,506	207,162	2,583,546	
- Commodity		-	-	-	-	-	-	-	
Total		38,822,420	27,971,737	6,538,840	115,629	1,405,506	207,162	2,583,546	
Additions to Utility Plant									
COVID-19 Regulatory Asset Adj excl. Res Adj		1,168,808							DISTPLT-CS
- Demand	COVID	-	-	-	-	-	-	-	0%
- Customer	COVID	1,168,808	970,188	87,949	1,553	69,025	35,206	4,886	100%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		1,168,808	970,188	87,949	1,553	69,025	35,206	4,886	
COVID-19 Residential Adjustment		(289,595)							DISTPLT-CS
- Demand	Res-Direct	-	-	-	-	-	-	-	0%
- Customer	Res-Direct	(289,595)	(289,595)	-	-	-	-	-	100%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(289,595)	(289,595)	-	-	-	-	-	
MD Electric Vehicle Program Reg Asset excl. Res Direct		81,186							DISTPLTxRES-CS
- Demand	DISTPLTxRES-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLTxRES-CS-C	81,186	-	30,095	549	7,821	1,206	41,514	100%
- Commodity	DISTPLTxRES-CS-E	-	-	-	-	-	-	-	0%
Total		81,186	-	30,095	549	7,821	1,206	41,514	
MD EV Reg Asset - Residential Direct		103,648							DISTPLT-CS
- Demand	Res-Direct	-	-	-	-	-	-	-	0%
- Customer	Res-Direct	103,648	103,648	-	-	-	-	-	100%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		103,648	103,648	-	-	-	-	-	
Total Additional to Utility Plant		1,064,046							
- Demand		-	-	-	-	-	-	-	
- Customer		1,064,046	784,241	118,044	2,102	76,846	36,412	46,400	
- Commodity		-	-	-	-	-	-	-	
Total		1,064,046	784,241	118,044	2,102	76,846	36,412	46,400	
Total Utility Plant		205,836,063							
- Demand		-	-	-	-	-	-	-	
- Customer		205,836,063	128,284,566	31,278,760	567,216	7,881,016	1,230,267	36,594,238	
- Commodity		-	-	-	-	-	-	-	
Total		**205,836,063**	**128,284,566**	**31,278,760**	**567,216**	**7,881,016**	**1,230,267**	**36,594,238**	
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
Distribution Plant A/D		(63,540,243)							DISTPLT-CS
- Demand	DISTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLT-CS-C	(63,540,243)	(38,108,382)	(9,427,441)	(172,103)	(2,449,977)	(377,793)	(13,004,547)	100%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		(63,540,243)	(38,108,382)	(9,427,441)	(172,103)	(2,449,977)	(377,793)	(13,004,547)	
General Plant A/D		(11,256,615)							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	(11,256,615)	(8,110,444)	(1,895,946)	(33,527)	(407,528)	(60,067)	(749,103)	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		(11,256,615)	(8,110,444)	(1,895,946)	(33,527)	(407,528)	(60,067)	(749,103)	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Intangible Plant A/D		(2,989,703)							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	(2,989,703)	(2,154,095)	(503,554)	(8,905)	(108,238)	(15,953)	(198,958)	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		(2,989,703)	(2,154,095)	(503,554)	(8,905)	(108,238)	(15,953)	(198,958)	
COVID Reg Asset A/D		(87,921)							COVIDREGASSET-CS
- Demand	COVIDREGASSET-CS-D	-	-	-	-	-	-	-	0%
- Customer	COVIDREGASSET-CS-C	(87,921)	(68,059)	(8,795)	(155)	(6,903)	(3,521)	(489)	100%
- Commodity	COVIDREGASSET-CS-E	-	-	-	-	-	-	-	0%
Total		(87,921)	(68,059)	(8,795)	(155)	(6,903)	(3,521)	(489)	
EV Reg Asset A/D		(18,483)							EVREGASSET-CS
- Demand	EVREGASSET-CS-D	-	-	-	-	-	-	-	0%
- Customer	EVREGASSET-CS-C	(18,483)	(10,365)	(3,009)	(55)	(782)	(121)	(4,151)	100%
- Commodity	EVREGASSET-CS-E	-	-	-	-	-	-	-	0%
Total		(18,483)	(10,365)	(3,009)	(55)	(782)	(121)	(4,151)	
CWIP A/D		(19,689)							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	(19,689)	(12,271)	(2,992)	(54)	(754)	(118)	(3,500)	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		(19,689)	(12,271)	(2,992)	(54)	(754)	(118)	(3,500)	
Total Accumulated Depreciation		(77,912,654)							
- Demand		-	-	-	-	-	-	-	
- Customer		(77,912,654)	(48,463,616)	(11,841,737)	(214,799)	(2,974,181)	(457,573)	(13,960,748)	
- Commodity		-	-	-	-	-	-	-	
Total Accumulated Depreciation		**(77,912,654)**	**(48,463,616)**	**(11,841,737)**	**(214,799)**	**(2,974,181)**	**(457,573)**	**(13,960,748)**	
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Construction Work in Progress		7,062,468							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	7,062,468	4,401,589	1,073,210	19,462	270,407	42,212	1,255,590	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		7,062,468	4,401,589	1,073,210	19,462	270,407	42,212	1,255,590	
Plant Held for Future Use		-							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	-	-	-	-	-	-	-	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Prepayments		-							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	-	-	-	-	-	-	-	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Working Capital		2,295,128							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	2,295,128	1,430,407	348,767	6,325	87,875	13,718	408,036	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		2,295,128	1,430,407	348,767	6,325	87,875	13,718	408,036	
ADIT		(31,486,287)							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	(31,486,287)	(19,623,406)	(4,784,643)	(86,766)	(1,205,542)	(188,191)	(5,597,740)	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		(31,486,287)	(19,623,406)	(4,784,643)	(86,766)	(1,205,542)	(188,191)	(5,597,740)	
Customer Advances		(612,971)							DISTPLT-CS
- Demand	DISTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLT-CS-C	(612,971)	(367,630)	(90,946)	(1,660)	(23,635)	(3,645)	(125,454)	100%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		(612,971)	(367,630)	(90,946)	(1,660)	(23,635)	(3,645)	(125,454)	
Customer Deposits		(1,958,453)							TOTPLT-CS
- Demand	Deposits	-	-	-	-	-	-	-	0%
- Customer	Deposits	(1,958,453)	(1,070,038)	(291,707)	-	(590,936)	-	(5,771)	100%
- Commodity	Deposits	-	-	-	-	-	-	-	0%
Total		(1,958,453)	(1,070,038)	(291,707)	-	(590,936)	-	(5,771)	
Deferred Investment Tax Credit		-							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	-	-	-	-	-	-	-	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Total Other Rate Base Items		(24,700,115)							
- Demand		-	-	-	-	-	-	-	
- Customer		(24,700,115)	(15,229,079)	(3,745,320)	(62,640)	(1,461,831)	(135,906)	(4,065,340)	
- Commodity		-	-	-	-	-	-	-	
Total		(24,700,115)	(15,229,079)	(3,745,320)	(62,640)	(1,461,831)	(135,906)	(4,065,340)	
Total Rate Base		**103,223,294**							
- Demand		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
- Customer		**103,223,294**	**64,591,871**	**15,691,703**	**289,778**	**3,445,004**	**636,788**	**18,568,150**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**103,223,294**	**64,591,871**	**15,691,703**	**289,778**	**3,445,004**	**636,788**	**18,568,150**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
OPERATIONS & MAINTENANCE EXPENSES									
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering		23,160							DistOpExp-CS
- Demand	DistOpExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistOpExp-CS-C	23,160	14,171	5,068	105	1,647	266	1,902	100%
- Commodity	DistOpExp-CS-E	-	-	-	-	-	-	-	0%
Total		23,160	14,171	5,068	105	1,647	266	1,902	
(581) Load Dispatching		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(582) Station Expenses		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(583) Overhead line expenses		226,558							OHLines-CS
- Demand	OHLines-CS-D	-	-	-	-	-	-	-	0%
- Customer	OHLines-CS-C	226,558	200,115	24,906	259	1,279	-	-	100%
- Commodity	OHLines-CS-E	-	-	-	-	-	-	-	0%
Total		226,558	200,115	24,906	259	1,279	-	-	
(584) Underground line expenses		74,177							UGLines-CS
- Demand	UGLines-CS-D	-	-	-	-	-	-	-	0%
- Customer	UGLines-CS-C	74,177	65,519	8,154	85	419	-	-	100%
- Commodity	UGLines-CS-E	-	-	-	-	-	-	-	0%
Total		74,177	65,519	8,154	85	419	-	-	
(585) Street lighting and signal system expenses		107,100							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	StreetLighting	107,100	-	-	-	-	-	107,100	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		107,100	-	-	-	-	-	107,100	
(586) Meter expenses		896,233							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Meters	896,233	532,314	252,310	5,567	91,038	15,005	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		896,233	532,314	252,310	5,567	91,038	15,005	-	
(588) Miscellaneous distribution expenses		1,496,762							DistOpExp-CS
- Demand	DistOpExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistOpExp-CS-C	1,496,762	915,856	327,537	6,784	106,438	17,222	122,926	100%
- Commodity	DistOpExp-CS-E	-	-	-	-	-	-	-	0%
Total		1,496,762	915,856	327,537	6,784	106,438	17,222	122,926	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(589) Rents		360,331							DistOpExp-CS
- Demand	DistOpExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistOpExp-CS-C	360,331	220,483	78,851	1,633	25,624	4,146	29,593	100%
- Commodity	DistOpExp-CS-E	-	-	-	-	-	-	-	0%
Total		360,331	220,483	78,851	1,633	25,624	4,146	29,593	
Total Dist. Operations Expenses		3,184,320							
- Demand		-	-	-	-	-	-	-	
- Customer		3,184,320	1,948,458	696,826	14,432	226,443	36,640	261,521	
- Commodity		-	-	-	-	-	-	-	
Total		3,184,320	1,948,458	696,826	14,432	226,443	36,640	261,521	
Maintenance Expense									
(590) Maintenance Supervision and Engineering		-							DistMtExp-CS
- Demand	DistMtExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistMtExp-CS-C	-	-	-	-	-	-	-	100%
- Commodity	DistMtExp-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(591) Maintenance of Structures		-							DistMtExp-CS
- Demand	DistMtExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistMtExp-CS-C	-	-	-	-	-	-	-	100%
- Commodity	DistMtExp-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
(592) Maintenance of Station Equipment		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(593) Maintenance of Overhead Lines		3,352,951							OHLines-CS
- Demand	OHLines-CS-D	-	-	-	-	-	-	-	0%
- Customer	OHLines-CS-C	3,352,951	2,961,607	368,594	3,829	18,921	-	-	100%
- Commodity	OHLines-CS-E	-	-	-	-	-	-	-	0%
Total		3,352,951	2,961,607	368,594	3,829	18,921	-	-	
(594) Maintenance of underground lines		48,327							UGLines-CS
- Demand	UGLines-CS-D	-	-	-	-	-	-	-	0%
- Customer	UGLines-CS-C	48,327	42,687	5,313	55	273	-	-	100%
- Commodity	UGLines-CS-E	-	-	-	-	-	-	-	0%
Total		48,327	42,687	5,313	55	273	-	-	
(595) Maintenance of line transformers		-							#N/A
- Demand		-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	
(596) Maintenance of street lighting and signal systems		465,742							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	StreetLighting	465,742	-	-	-	-	-	465,742	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		465,742	-	-	-	-	-	465,742	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
(597) Maintenance of meters		914,278							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Meters	914,278	543,032	257,390	5,679	92,871	15,307	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		914,278	543,032	257,390	5,679	92,871	15,307	-	
(598) Maintenance of miscellaneous distribution plant		31,075							DistMtExp-CS
- Demand	DistMtExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	DistMtExp-CS-C	31,075	23,055	4,103	62	728	99	3,027	100%
- Commodity	DistMtExp-CS-E	-	-	-	-	-	-	-	0%
Total		31,075	23,055	4,103	62	728	99	3,027	
Total Dist. Maintenance Expenses		4,812,374							
- Demand		-	-	-	-	-	-	-	
- Customer		4,812,374	3,570,381	635,399	9,625	112,793	15,407	468,769	
- Commodity		-	-	-	-	-	-	-	
Total		4,812,374	3,570,381	635,399	9,625	112,793	15,407	468,769	
Total Distribution Expenses		7,996,694							
- Demand		-	-	-	-	-	-	-	
- Customer		7,996,694	5,518,839	1,332,225	24,057	339,236	52,046	730,290	
- Commodity		-	-	-	-	-	-	-	
Total		7,996,694	5,518,839	1,332,225	24,057	339,236	52,046	730,290	
Customer Accounts and Services									
Meter Reading & Billing		6,854,217							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	MeterReading	6,854,217	5,857,097	934,546	12,631	44,634	-	5,309	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		6,854,217	5,857,097	934,546	12,631	44,634	-	5,309	
Other-Direct to Other		-							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Customers-SEC	-	-	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Uncollectibles		1,132,614							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Uncollectibles	1,132,614	1,131,744	330	6	259	275	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		1,132,614	1,131,744	330	6	259	275	-	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
Misc. Cust Serv and Info Exp		2,381,813							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	CustServices	2,381,813	2,178,507	182,913	2,013	6,213	-	12,167	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		2,381,813	2,178,507	182,913	2,013	6,213	-	12,167	
Customer Rebates & Incentives		-							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Customers-SEC	-	-	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Customer Assistance		233,396							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	CustAssist	233,396	233,396	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		233,396	233,396	-	-	-	-	-	
Sales Expense		1							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Customers-SEC	1	1	0	0	0	-	0	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		1	1	0	0	0	-	0	
All Other Cust Accts & Services		-							CUS
- Demand		-	-	-	-	-	-	-	0%
- Customer	Customers-SEC	-	-	-	-	-	-	-	100%
- Commodity		-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Total Customer Accounts and Services		10,602,041							
- Demand		-	-	-	-	-	-	-	
- Customer		10,602,041	9,400,745	1,117,789	14,650	51,106	275	17,476	
- Commodity		-	-	-	-	-	-	-	
Total		10,602,041	9,400,745	1,117,789	14,650	51,106	275	17,476	
Administrative & General Expense									
Administrative and General Salaries		1,553,168							NONAGLAB-CS
- Demand	NONAGLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	NONAGLAB-CS-C	1,553,168	1,119,065	261,599	4,626	56,230	8,288	103,360	100%
- Commodity	NONAGLAB-CS-E	-	-	-	-	-	-	-	0%
Total		1,553,168	1,119,065	261,599	4,626	56,230	8,288	103,360	
Outside Services		2,990,398							NONAGLAB-CS
- Demand	NONAGLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	NONAGLAB-CS-C	2,990,398	2,154,596	503,671	8,907	108,263	15,957	199,004	100%
- Commodity	NONAGLAB-CS-E	-	-	-	-	-	-	-	0%
Total		2,990,398	2,154,596	503,671	8,907	108,263	15,957	199,004	
Employee Benefits (Acct. 926)		(927,037)							NONAGLAB-CS
- Demand	NONAGLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	NONAGLAB-CS-C	(927,037)	(667,935)	(156,140)	(2,761)	(33,562)	(4,947)	(61,692)	100%
- Commodity	NONAGLAB-CS-E	-	-	-	-	-	-	-	0%
Total		(927,037)	(667,935)	(156,140)	(2,761)	(33,562)	(4,947)	(61,692)	
Regulatory Commission Expenses (Acct 928)		160,601							DISTPLT-CS
- Demand	SalesREV	-	-	-	-	-	-	-	0%
- Customer	SalesREV	160,601	102,402	29,826	511	20,174	1,254	6,433	100%
- Commodity	SalesREV	-	-	-	-	-	-	-	0%
Total		160,601	102,402	29,826	511	20,174	1,254	6,433	
General Advertising Expense		18,984							OpExp-CS
- Demand	OpExp-CS-D	-	-	-	-	-	-	-	0%
- Customer	OpExp-CS-C	18,984	15,229	2,501	40	398	53	763	100%
- Commodity	OpExp-CS-E	-	-	-	-	-	-	-	0%
Total		18,984	15,229	2,501	40	398	53	763	
All Other O&M		843,375							NONAGLAB-CS
- Demand	NONAGLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	NONAGLAB-CS-C	843,375	607,655	142,049	2,512	30,533	4,500	56,125	100%
- Commodity	NONAGLAB-CS-E	-	-	-	-	-	-	-	0%
Total		843,375	607,655	142,049	2,512	30,533	4,500	56,125	
Total A&G Expense		4,639,488							
- Demand		-	-	-	-	-	-	-	
- Customer		4,639,488	3,331,013	783,506	13,834	182,037	25,106	303,993	
- Commodity		-	-	-	-	-	-	-	
Total		4,639,488	3,331,013	783,506	13,834	182,037	25,106	303,993	
Total O&M Expenses		23,238,223							
- Demand		-	-	-	-	-	-	-	
- Customer		23,238,223	18,250,596	3,233,520	52,541	572,378	77,427	1,051,760	
- Commodity		-	-	-	-	-	-	-	
Total		**23,238,223**	**18,250,596**	**3,233,520**	**52,541**	**572,378**	**77,427**	**1,051,760**	

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
DEPRECIATION EXPENSE									
Depreciation Expense									
Distribution Plant DeprExp		3,475,137							DISTPLT-CS
- Demand	DISTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLT-CS-C	3,475,137	2,084,220	515,605	9,413	133,994	20,662	711,244	100%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		3,475,137	2,084,220	515,605	9,413	133,994	20,662	711,244	
General Plant DeprExp		1,206,145							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	1,206,145	869,034	203,150	3,592	43,667	6,436	80,266	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		1,206,145	869,034	203,150	3,592	43,667	6,436	80,266	
Intangible Plant DeprExp		263,789							LABOR-CS
- Demand	LABOR-CS-D	-	-	-	-	-	-	-	0%
- Customer	LABOR-CS-C	263,789	190,061	44,430	786	9,550	1,408	17,555	100%
- Commodity	LABOR-CS-E	-	-	-	-	-	-	-	0%
Total		263,789	190,061	44,430	786	9,550	1,408	17,555	
Total Depreciation Expenses		4,945,072							
- Demand		-	-	-	-	-	-	-	
- Customer		4,945,072	3,143,315	763,185	13,791	187,211	28,506	809,064	
- Commodity		-	-	-	-	-	-	-	
Total		**4,945,072**	**3,143,315**	**763,185**	**13,791**	**187,211**	**28,506**	**809,064**	
Regulatory Debits and Credits									
MD EDIS		(54,955)							DEM
- Demand	1NCP-SEC	(54,955)	(35,588)	(7,673)	(205)	(11,143)	-	(345)	100%
- Customer		-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	0%
Total		(54,955)	(35,588)	(7,673)	(205)	(11,143)	-	(345)	
MD Electric Vehicle Program		42,627							EVREGASSET-CS
- Demand	EVREGASSET-CS-D	-	-	-	-	-	-	-	0%
- Customer	EVREGASSET-CS-C	42,627	23,904	6,941	127	1,804	278	9,574	100%
- Commodity	EVREGASSET-CS-E	-	-	-	-	-	-	-	0%
Total		42,627	23,904	6,941	127	1,804	278	9,574	
MD Conservation Voltage Reduction (CVR)		-							DISTPLT-CS
- Demand	DISTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLT-CS-C	-	-	-	-	-	-	-	100%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		-	-	-	-	-	-	-	
Deferral of Rate Case Expenses		(10,531)							DISTPLT-CS
- Demand	DISTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTPLT-CS-C	(10,531)	(6,316)	(1,562)	(29)	(406)	(63)	(2,155)	100%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		(10,531)	(6,316)	(1,562)	(29)	(406)	(63)	(2,155)	
COVID-19		233,762							DISTPLT-CS
- Demand	COVID	-	-	-	-	-	-	-	0%
- Customer	COVID	233,762	194,038	17,590	311	13,805	7,041	977	100%
- Commodity	COVID	-	-	-	-	-	-	-	0%
Total		233,762	194,038	17,590	311	13,805	7,041	977	
COVID-19 - Residential Adjustment		(57,919)							DISTPLT-CS
- Demand	Res-Direct	-	-	-	-	-	-	-	0%
- Customer	Res-Direct	(57,919)	(57,919)	-	-	-	-	-	100%
- Commodity	Res-Direct	-	-	-	-	-	-	-	0%
Total		(57,919)	(57,919)	-	-	-	-	-	
Total Regulatory Debits and Credits		152,984							
- Demand		(54,955)	(35,588)	(7,673)	(205)	(11,143)	-	(345)	
- Customer		207,939	153,707	22,968	409	15,203	7,257	8,396	
- Commodity		-	-	-	-	-	-	-	
Total		152,984	118,118	15,295	204	4,059	7,257	8,051	
Taxes Other than Income									
Distribution Payroll Taxes		176,276							DISTLAB-CS
- Demand	DISTLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	DISTLAB-CS-C	176,276	109,245	33,995	676	10,306	1,645	20,409	100%
- Commodity	DISTLAB-CS-E	-	-	-	-	-	-	-	0%
Total		176,276	109,245	33,995	676	10,306	1,645	20,409	
Customer Account Payroll Taxes		228,896							CUSTLAB-CS
- Demand	CUSTLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	CUSTLAB-CS-C	228,896	195,719	31,088	420	1,483	-	186	100%
- Commodity	CUSTLAB-CS-E	-	-	-	-	-	-	-	0%
Total		228,896	195,719	31,088	420	1,483	-	186	
A&G Payroll Taxes		5,212							AGLAB-CS
- Demand	AGLAB-CS-D	-	-	-	-	-	-	-	0%
- Customer	AGLAB-CS-C	5,212	3,755	878	16	189	28	347	100%

The Potomac Edison Company (Maryland) Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG	Classification Factor
- Commodity	AGLAB-CS-E	-	-	-	-	-	-	-	0%
Total		5,212	3,755	878	16	189	28	347	
Gross Receipt Taxes		971,296							TOTPLT-CS
- Demand	Revenue	-	-	-	-	-	-	-	0%
- Customer	Revenue	971,296	603,652	178,498	3,151	140,091	9,948	35,956	100%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		971,296	603,652	178,498	3,151	140,091	9,948	35,956	
Property Taxes		1,882,439							TOTPLT-CS
- Demand	TOTPLT-CS-D	-	-	-	-	-	-	-	0%
- Customer	TOTPLT-CS-C	1,882,439	1,173,205	286,055	5,187	72,074	11,251	334,666	100%
- Commodity	TOTPLT-CS-E	-	-	-	-	-	-	-	0%
Total		1,882,439	1,173,205	286,055	5,187	72,074	11,251	334,666	
Sales & Use Tax		(28,276)							TOTPLT-CS
- Demand	Revenue	-	-	-	-	-	-	-	0%
- Customer	Revenue	(28,276)	(17,573)	(5,196)	(92)	(4,078)	(290)	(1,047)	100%
- Commodity	Revenue	-	-	-	-	-	-	-	0%
Total		(28,276)	(17,573)	(5,196)	(92)	(4,078)	(290)	(1,047)	
Montgomery County Fuel Energy		1,328,077							TOTPLT-CS
- Demand	MontCoFuel	-	-	-	-	-	-	-	0%
- Customer	MontCoFuel	1,328,077	635,350	241,947	5,202	426,527	-	19,052	100%
- Commodity	MontCoFuel	-	-	-	-	-	-	-	0%
Total		1,328,077	635,350	241,947	5,202	426,527	-	19,052	
Other Taxes		90							RB-CS
- Demand	RB-CS-D	-	-	-	-	-	-	-	0%
- Customer	RB-CS-C	90	56	14	0	3	1	16	100%
- Commodity	RB-CS-E	-	-	-	-	-	-	-	0%
Total		90	56	14	0	3	1	16	
Total Taxes Other than Income		4,564,010							
- Demand		-	-	-	-	-	-	-	
- Customer		4,564,010	2,703,409	767,279	14,560	646,594	22,583	409,585	
- Commodity		-	-	-	-	-	-	-	
Total Taxes Other than Income		4,564,010	2,703,409	767,279	14,560	646,594	22,583	409,585	
Total Operating Expenses		**32,900,289**							
- Demand		**(54,955)**	**(35,588)**	**(7,673)**	**(205)**	**(11,143)**	**-**	**(345)**	
- Customer		**32,955,244**	**24,251,027**	**4,786,952**	**81,301**	**1,421,386**	**135,773**	**2,278,805**	
- Commodity		**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total		**32,900,289**	**24,215,439**	**4,779,278**	**81,096**	**1,410,243**	**135,773**	**2,278,460**	

The Potomac Edison Company (Maryland) Allocation Summary	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
Revenue Requirement							
Sub-Transmission							
- Demand	36,261,840	22,645,044	3,830,873	96,458	8,064,548	1,519,431	105,486
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Primary							
- Demand	27,439,862	16,715,391	3,780,688	107,507	6,538,344	78,997	218,934
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Secondary							
- Demand	80,600,091	51,524,109	11,483,816	299,963	16,535,550	90,079	666,575
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Sub-Transmission							
- Demand	(54,955)	(35,588)	(7,673)	(205)	(11,143)	-	(345)
- Customer	42,088,695	30,019,581	6,150,685	107,085	1,731,168	192,349	3,887,828
- Commodity	-	-	-	-	-	-	-
Total Revenue Requirement							
- Demand	**144,246,838**	**90,848,956**	**19,087,703**	**503,722**	**31,127,300**	**1,688,507**	**990,650**
- Customer	**42,088,695**	**30,019,581**	**6,150,685**	**107,085**	**1,731,168**	**192,349**	**3,887,828**
- Commodity	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Revenue Requirement	**186,335,533**	**120,868,536**	**25,238,388**	**610,807**	**32,858,468**	**1,880,856**	**4,878,478**

The Potomac Edison Company (Maryland) Allocation Summary	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
Rate Base							
Sub-Transmission							
- Demand	137,876,780	87,245,134	13,521,641	358,821	30,286,130	6,381,146	83,908
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Primary							
- Demand	121,783,036	75,040,026	16,288,345	488,920	28,932,827	301,140	731,779
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Secondary							
- Demand	355,642,109	231,308,568	49,463,829	1,347,718	71,095,237	175,222	2,251,535
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Sub-Transmission							
- Demand	-	-	-	-	-	-	-
- Customer	103,223,294	64,591,871	15,691,703	289,778	3,445,004	636,788	18,568,150
- Commodity	-	-	-	-	-	-	-
Total Rate Base							
- Demand	**615,301,924**	**393,593,728**	**79,273,814**	**2,195,459**	**130,314,194**	**6,857,508**	**3,067,222**
- Customer	**103,223,294**	**64,591,871**	**15,691,703**	**289,778**	**3,445,004**	**636,788**	**18,568,150**
- Commodity	-	-	-	-	-	-	-
Total Rate Base	**718,525,219**	**458,185,599**	**94,965,517**	**2,485,237**	**133,759,198**	**7,494,295**	**21,635,372**

The Potomac Edison Company (Maryland) Allocation Summary	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
Total Expenses							
Sub-Transmission							
- Demand	23,965,511	14,853,379	2,655,736	64,530	5,341,157	952,493	98,215
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Primary							
- Demand	16,587,252	10,013,737	2,365,102	64,003	3,936,645	52,242	155,522
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Secondary							
- Demand	48,920,028	30,866,466	7,185,018	180,045	10,142,521	74,511	471,468
- Customer	-	-	-	-	-	-	-
- Commodity	-	-	-	-	-	-	-
Sub-Transmission							
- Demand	(54,955)	(35,588)	(7,673)	(205)	(11,143)	-	(345)
- Customer	32,955,244	24,251,027	4,786,952	81,301	1,421,386	135,773	2,278,805
- Commodity	-	-	-	-	-	-	-
Total Expenses							
- Demand	**89,417,835**	**55,697,994**	**12,198,182**	**308,373**	**19,409,180**	**1,079,246**	**724,860**
- Customer	**32,955,244**	**24,251,027**	**4,786,952**	**81,301**	**1,421,386**	**135,773**	**2,278,805**
- Commodity	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Expenses	**122,373,079**	**79,949,021**	**16,985,134**	**389,674**	**20,830,566**	**1,215,019**	**3,003,665**

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
UTILITY PLANT				
Distribution Plant				
(360) Land and Land Rights				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				
(361) Structures and Improvements				
- Demand	12CP-SUB	1NCP-PRI		
- Customer				
- Commodity				
Total				
(362) Station Equipment				
- Demand	12CP-SUB	1NCP-PRI		
- Customer				
- Commodity				
Total				
(362) Station Equipment - Capacitors				
- Demand	12CP-SUB			
- Customer				
- Commodity				
Total				
(364) Poles, Towers & Fixtures				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				
(365) Overhead Conductors & Devices				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				
(366) Underground Conduit				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				
(367) Underground Conductors & Device				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				
(368) Line Transformers				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
(368) Line Transformers - Capacitors				
- Demand			12CP-GEN	
- Customer				
- Commodity				
Total				
(369) Services				
- Demand				1NCPxLT-SEC
- Customer				CUSxLT-SEC
- Commodity				
Total				
(370, 371) Meters and Installation				
- Demand				
- Customer				Meters
- Commodity				
Total				
Street Lighting & Signal Systems				
- Demand				
- Customer				StreetLighting
- Commodity				
Total				
General and Intangible Plant				
General Plant				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				
Intangible Plant				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
Additions to Utility Plant				
COVID-19 Regulatory Asset Adj excl. Res Adj				
- Demand	COVID	COVID	COVID	COVID
- Customer	COVID	COVID	COVID	COVID
- Commodity	COVID	COVID	COVID	COVID
Total				
COVID-19 Residential Adjustment				
- Demand	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Customer	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Commodity	Res-Direct	Res-Direct	Res-Direct	Res-Direct
Total				
MD Electric Vehicle Program Reg Asset excl. Res Direct				
- Demand	DISTPLTxRES-SUB-D	DISTPLTxRES-PRI-D	DISTPLTxRES-SEC-D	DISTPLTxRES-CS-D
- Customer	DISTPLTxRES-SUB-C	DISTPLTxRES-PRI-C	DISTPLTxRES-SEC-C	DISTPLTxRES-CS-C
- Commodity	DISTPLTxRES-SUB-E	DISTPLTxRES-PRI-E	DISTPLTxRES-SEC-E	DISTPLTxRES-CS-E
Total				
MD EV Reg Asset - Residential Direct				
- Demand	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Customer	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Commodity	Res-Direct	Res-Direct	Res-Direct	Res-Direct
Total				
ACCUMULATED DEPRECIATION				
Accumulated Depreciation				
Distribution Plant A/D				
- Demand	DISTPLT-SUB-D	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-SUB-C	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-SUB-E	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total				
General Plant A/D				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				
Intangible Plant A/D				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				
COVID Reg Asset A/D				
- Demand	COVIDREGASSET-SUB-D	COVIDREGASSET-PRI-D	COVIDREGASSET-SEC-D	COVIDREGASSET-CS-D
- Customer	COVIDREGASSET-SUB-C	COVIDREGASSET-PRI-C	COVIDREGASSET-SEC-C	COVIDREGASSET-CS-C
- Commodity	COVIDREGASSET-SUB-E	COVIDREGASSET-PRI-E	COVIDREGASSET-SEC-E	COVIDREGASSET-CS-E
Total				
EV Reg Asset A/D				
- Demand	EVREGASSET-SUB-D	EVREGASSET-PRI-D	EVREGASSET-SEC-D	EVREGASSET-CS-D
- Customer	EVREGASSET-SUB-C	EVREGASSET-PRI-C	EVREGASSET-SEC-C	EVREGASSET-CS-C
- Commodity	EVREGASSET-SUB-E	EVREGASSET-PRI-E	EVREGASSET-SEC-E	EVREGASSET-CS-E
Total				

The Potomac Edison Company (Maryland) **Allocation to Customer Classes** **ALLOCATION FACTORS**	**Sub-Transmission**	**Primary**	**Secondary**	**Customer Service**
CWIP A/D				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
OTHER RATE BASE ITEMS				
Other Rate Base Items				
Construction Work in Progress				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
Plant Held for Future Use				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
Prepayments				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
Working Capital				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
ADIT				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
Customer Advances				
- Demand	DISTPLT-SUB-D	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-SUB-C	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-SUB-E	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
Customer Deposits				
- Demand	Deposits	Deposits	Deposits	Deposits
- Customer	Deposits	Deposits	Deposits	Deposits
- Commodity	Deposits	Deposits	Deposits	Deposits
Total				
Deferred Investment Tax Credit				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
OPERATIONS & MAINTENANCE EXPENSES				
Distribution Expenses				
Operations Expenses				
(580) Operation Supervision & Engineering				
- Demand	DistOpExp-SUB-D	DistOpExp-PRI-D	DistOpExp-SEC-D	DistOpExp-CS-D
- Customer	DistOpExp-SUB-C	DistOpExp-PRI-C	DistOpExp-SEC-C	DistOpExp-CS-C
- Commodity	DistOpExp-SUB-E	DistOpExp-PRI-E	DistOpExp-SEC-E	DistOpExp-CS-E
Total				
(581) Load Dispatching				
- Demand		1NCP-PRI		
- Customer				
- Commodity				
Total				
(582) Station Expenses				
- Demand		1NCP-PRI		
- Customer				
- Commodity				
Total				
(583) Overhead line expenses				
- Demand	OHLines-SUB-D	OHLines-PRI-D	OHLines-SEC-D	OHLines-CS-D
- Customer	OHLines-SUB-C	OHLines-PRI-C	OHLines-SEC-C	OHLines-CS-C
- Commodity	OHLines-SUB-E	OHLines-PRI-E	OHLines-SEC-E	OHLines-CS-E
Total				
(584) Underground line expenses				
- Demand	UGLines-SUB-D	UGLines-PRI-D	UGLines-SEC-D	UGLines-CS-D
- Customer	UGLines-SUB-C	UGLines-PRI-C	UGLines-SEC-C	UGLines-CS-C
- Commodity	UGLines-SUB-E	UGLines-PRI-E	UGLines-SEC-E	UGLines-CS-E
Total				
(585) Street lighting and signal system expenses				
- Demand				
- Customer				StreetLighting
- Commodity				
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
(586) Meter expenses				
- Demand				
- Customer				Meters
- Commodity				
Total				
(588) Miscellaneous distribution expenses				
- Demand	DistOpExp-SUB-D	DistOpExp-PRI-D	DistOpExp-SEC-D	DistOpExp-CS-D
- Customer	DistOpExp-SUB-C	DistOpExp-PRI-C	DistOpExp-SEC-C	DistOpExp-CS-C
- Commodity	DistOpExp-SUB-E	DistOpExp-PRI-E	DistOpExp-SEC-E	DistOpExp-CS-E
Total				
(589) Rents				
- Demand	DistOpExp-SUB-D	DistOpExp-PRI-D	DistOpExp-SEC-D	DistOpExp-CS-D
- Customer	DistOpExp-SUB-C	DistOpExp-PRI-C	DistOpExp-SEC-C	DistOpExp-CS-C
- Commodity	DistOpExp-SUB-E	DistOpExp-PRI-E	DistOpExp-SEC-E	DistOpExp-CS-E
Total				
Maintenance Expense				
(590) Maintenance Supervision and Engineering				
- Demand	DistMtExp-SUB-D	DistMtExp-PRI-D	DistMtExp-SEC-D	DistMtExp-CS-D
- Customer	DistMtExp-SUB-C	DistMtExp-PRI-C	DistMtExp-SEC-C	DistMtExp-CS-C
- Commodity	DistMtExp-SUB-E	DistMtExp-PRI-E	DistMtExp-SEC-E	DistMtExp-CS-E
Total				
(591) Maintenance of Structures				
- Demand	DistMtExp-SUB-D	DistMtExp-PRI-D	DistMtExp-SEC-D	DistMtExp-CS-D
- Customer	DistMtExp-SUB-C	DistMtExp-PRI-C	DistMtExp-SEC-C	DistMtExp-CS-C
- Commodity	DistMtExp-SUB-E	DistMtExp-PRI-E	DistMtExp-SEC-E	DistMtExp-CS-E
Total				
(592) Maintenance of Station Equipment				
- Demand		1NCP-PRI		
- Customer				
- Commodity				
Total				
(593) Maintenance of Overhead Lines				
- Demand	OHLines-SUB-D	OHLines-PRI-D	OHLines-SEC-D	OHLines-CS-D
- Customer	OHLines-SUB-C	OHLines-PRI-C	OHLines-SEC-C	OHLines-CS-C
- Commodity	OHLines-SUB-E	OHLines-PRI-E	OHLines-SEC-E	OHLines-CS-E
Total				
(594) Maintenance of underground lines				
- Demand	UGLines-SUB-D	UGLines-PRI-D	UGLines-SEC-D	UGLines-CS-D
- Customer	UGLines-SUB-C	UGLines-PRI-C	UGLines-SEC-C	UGLines-CS-C
- Commodity	UGLines-SUB-E	UGLines-PRI-E	UGLines-SEC-E	UGLines-CS-E
Total				
(595) Maintenance of line transformers				
- Demand	12CP-SUB	1NCP-PRI	1NCP-SEC	
- Customer		Customers-PRI	Customers-SEC	
- Commodity				
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
(596) Maintenance of street lighting and signal systems				
- Demand				
- Customer				StreetLighting
- Commodity				
Total				
(597) Maintenance of meters				
- Demand				
- Customer				Meters
- Commodity				
Total				
(598) Maintenance of miscellaneous distribution plant				
- Demand	DistMtExp-SUB-D	DistMtExp-PRI-D	DistMtExp-SEC-D	DistMtExp-CS-D
- Customer	DistMtExp-SUB-C	DistMtExp-PRI-C	DistMtExp-SEC-C	DistMtExp-CS-C
- Commodity	DistMtExp-SUB-E	DistMtExp-PRI-E	DistMtExp-SEC-E	DistMtExp-CS-E
Total				
Customer Accounts and Services				
Meter Reading & Billing				
- Demand				
- Customer				MeterReading
- Commodity				
Total				
Other-Direct to Other				
- Demand				
- Customer				Customers-SEC
- Commodity				
Total				
Uncollectibles				
- Demand				
- Customer				Uncollectibles
- Commodity				
Total				
Misc. Cust Serv and Info Exp				
- Demand				
- Customer				CustServices
- Commodity				
Total				
Customer Rebates & Incentives				
- Demand				
- Customer				Customers-SEC
- Commodity				
Total				
Customer Assistance				
- Demand				
- Customer				CustAssist
- Commodity				
Total				

The Potomac Edison Company (Maryland) **Allocation to Customer Classes** **ALLOCATION FACTORS**	**Sub-Transmission**	**Primary**	**Secondary**	**Customer Service**
Sales Expense				
- Demand				
- Customer				Customers-SEC
- Commodity				
Total				
All Other Cust Accts & Services				
- Demand				
- Customer				Customers-SEC
- Commodity				
Total				
Administrative & General Expense				
Administrative and General Salaries				
- Demand	NONAGLAB-SUB-D	NONAGLAB-PRI-D	NONAGLAB-SEC-D	NONAGLAB-CS-D
- Customer	NONAGLAB-SUB-C	NONAGLAB-PRI-C	NONAGLAB-SEC-C	NONAGLAB-CS-C
- Commodity	NONAGLAB-SUB-E	NONAGLAB-PRI-E	NONAGLAB-SEC-E	NONAGLAB-CS-E
Total				
Outside Services				
- Demand	NONAGLAB-SUB-D	NONAGLAB-PRI-D	NONAGLAB-SEC-D	NONAGLAB-CS-D
- Customer	NONAGLAB-SUB-C	NONAGLAB-PRI-C	NONAGLAB-SEC-C	NONAGLAB-CS-C
- Commodity	NONAGLAB-SUB-E	NONAGLAB-PRI-E	NONAGLAB-SEC-E	NONAGLAB-CS-E
Total				
Employee Benefits (Acct. 926)				
- Demand	NONAGLAB-SUB-D	NONAGLAB-PRI-D	NONAGLAB-SEC-D	NONAGLAB-CS-D
- Customer	NONAGLAB-SUB-C	NONAGLAB-PRI-C	NONAGLAB-SEC-C	NONAGLAB-CS-C
- Commodity	NONAGLAB-SUB-E	NONAGLAB-PRI-E	NONAGLAB-SEC-E	NONAGLAB-CS-E
Total				
Regulatory Commission Expenses (Acct 928)				
- Demand	SalesREV	SalesREV	SalesREV	SalesREV
- Customer	SalesREV	SalesREV	SalesREV	SalesREV
- Commodity	SalesREV	SalesREV	SalesREV	SalesREV
Total				
General Advertising Expense				
- Demand	OpExp-SUB-D	OpExp-PRI-D	OpExp-SEC-D	OpExp-CS-D
- Customer	OpExp-SUB-C	OpExp-PRI-C	OpExp-SEC-C	OpExp-CS-C
- Commodity	OpExp-SUB-E	OpExp-PRI-E	OpExp-SEC-E	OpExp-CS-E
Total				
All Other O&M				
- Demand	NONAGLAB-SUB-D	NONAGLAB-PRI-D	NONAGLAB-SEC-D	NONAGLAB-CS-D
- Customer	NONAGLAB-SUB-C	NONAGLAB-PRI-C	NONAGLAB-SEC-C	NONAGLAB-CS-C
- Commodity	NONAGLAB-SUB-E	NONAGLAB-PRI-E	NONAGLAB-SEC-E	NONAGLAB-CS-E
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
DEPRECIATION EXPENSE				
Depreciation Expense				
Distribution Plant DeprExp				
- Demand	DISTPLT-SUB-D	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-SUB-C	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-SUB-E	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total				
General Plant DeprExp				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				
Intangible Plant DeprExp				
- Demand	LABOR-SUB-D	LABOR-PRI-D	LABOR-SEC-D	LABOR-CS-D
- Customer	LABOR-SUB-C	LABOR-PRI-C	LABOR-SEC-C	LABOR-CS-C
- Commodity	LABOR-SUB-E	LABOR-PRI-E	LABOR-SEC-E	LABOR-CS-E
Total				
Regulatory Debits and Credits				
MD EDIS				
- Demand	1NCP-PRI	1NCP-PRI	1NCP-SEC	1NCP-SEC
- Customer				
- Commodity				
Total				
MD Electric Vehicle Program				
- Demand	EVREGASSET-SUB-D	EVREGASSET-PRI-D	EVREGASSET-SEC-D	EVREGASSET-CS-D
- Customer	EVREGASSET-SUB-C	EVREGASSET-PRI-C	EVREGASSET-SEC-C	EVREGASSET-CS-C
- Commodity	EVREGASSET-SUB-E	EVREGASSET-PRI-E	EVREGASSET-SEC-E	EVREGASSET-CS-E
Total				
MD Conservation Voltage Reduction (CVR)				
- Demand	DISTPLT-SUB-D	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-SUB-C	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-SUB-E	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total				
Deferral of Rate Case Expenses				
- Demand	DISTPLT-SUB-D	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-SUB-C	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-SUB-E	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total				
COVID-19				
- Demand	COVID	COVID	COVID	COVID
- Customer	COVID	COVID	COVID	COVID
- Commodity	COVID	COVID	COVID	COVID
Total				
COVID-19 - Residential Adjustment				
- Demand	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Customer	Res-Direct	Res-Direct	Res-Direct	Res-Direct
- Commodity	Res-Direct	Res-Direct	Res-Direct	Res-Direct
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes ALLOCATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
TAXES				
Taxes Other than Income				
Distribution Payroll Taxes				
- Demand	DISTLAB-SUB-D	DISTLAB-PRI-D	DISTLAB-SEC-D	DISTLAB-CS-D
- Customer	DISTLAB-SUB-C	DISTLAB-PRI-C	DISTLAB-SEC-C	DISTLAB-CS-C
- Commodity	DISTLAB-SUB-E	DISTLAB-PRI-E	DISTLAB-SEC-E	DISTLAB-CS-E
Total				
Customer Account Payroll Taxes				
- Demand	CUSTLAB-SUB-D	CUSTLAB-PRI-D	CUSTLAB-SEC-D	CUSTLAB-CS-D
- Customer	CUSTLAB-SUB-C	CUSTLAB-PRI-C	CUSTLAB-SEC-C	CUSTLAB-CS-C
- Commodity	CUSTLAB-SUB-E	CUSTLAB-PRI-E	CUSTLAB-SEC-E	CUSTLAB-CS-E
Total				
A&G Payroll Taxes				
- Demand	AGLAB-SUB-D	AGLAB-PRI-D	AGLAB-SEC-D	AGLAB-CS-D
- Customer	AGLAB-SUB-C	AGLAB-PRI-C	AGLAB-SEC-C	AGLAB-CS-C
- Commodity	AGLAB-SUB-E	AGLAB-PRI-E	AGLAB-SEC-E	AGLAB-CS-E
Total				
Gross Receipt Taxes				
- Demand	Revenue	Revenue	Revenue	Revenue
- Customer	Revenue	Revenue	Revenue	Revenue
- Commodity	Revenue	Revenue	Revenue	Revenue
Total				
Property Taxes				
- Demand	TOTPLT-SUB-D	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-SUB-C	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-SUB-E	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Total				
Sales & Use Tax				
- Demand	Revenue	Revenue	Revenue	Revenue
- Customer	Revenue	Revenue	Revenue	Revenue
- Commodity	Revenue	Revenue	Revenue	Revenue
Total				
Montgomery County Fuel Energy				
- Demand	MontCoFuel	MontCoFuel	MontCoFuel	MontCoFuel
- Customer	MontCoFuel	MontCoFuel	MontCoFuel	MontCoFuel
- Commodity	MontCoFuel	MontCoFuel	MontCoFuel	MontCoFuel
Total				
Other Taxes				
- Demand	RB-SUB-D	RB-PRI-D	RB-SEC-D	RB-CS-D
- Customer	RB-SUB-C	RB-PRI-C	RB-SEC-C	RB-CS-C
- Commodity	RB-SUB-E	RB-PRI-E	RB-SEC-E	RB-CS-E
Total				

The Potomac Edison Company (Maryland) Allocation to Customer Classes CLASSIFICATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
UTILITY PLANT				
Distribution Plant				
(360) Land and Land Rights	DEM	360P	360S	CUS
(361) Structures and Improvements	DEM	DEM		
(362) Station Equipment	DEM	DEM		
(362) Station Equipment - Capacitors	DEM	DEM		
(364) Poles, Towers & Fixtures	DEM	364P	364S	CUS
(365) Overhead Conductors & Devices	DEM	365P	365S	
(366) Underground Conduit	DEM	366P	366S	
(367) Underground Conductors & Device	DEM	367P	367S	
(368) Line Transformers	DEM	368P	368S	
(368) Line Transformers - Capacitors			DEM	
(369) Services				369
(370, 371) Meters and Installation				CUS
Street Lighting & Signal Systems				CUS
General and Intangible Plant				
General Plant	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
Intangible Plant	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
Additions to Utility Plant				
COVID-19 Regulatory Asset Adj excl. Res Adj	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
COVID-19 Residential Adjustment	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
MD Electric Vehicle Program Reg Asset excl. Res D	DISTPLTxRES-SUB	DISTPLTxRES-PRI	DISTPLTxRES-SEC	DISTPLTxRES-CS
MD EV Reg Asset - Residential Direct	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS

The Potomac Edison Company (Maryland) Allocation to Customer Classes CLASSIFICATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
ACCUMULATED DEPRECIATION				
Accumulated Depreciation				
Distribution Plant A/D	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
General Plant A/D	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
Intangible Plant A/D	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
COVID Reg Asset A/D	COVIDREGASSET-SUB	COVIDREGASSET-PRI	COVIDREGASSET-SEC	COVIDREGASSET-CS
EV Reg Asset A/D	EVREGASSET-SUB	EVREGASSET-PRI	EVREGASSET-SEC	EVREGASSET-CS
CWIP A/D	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
OTHER RATE BASE ITEMS				
Other Rate Base Items				
Construction Work in Progress	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Plant Held for Future Use	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Prepayments	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Working Capital	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
ADIT	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Customer Advances	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Customer Deposits	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Deferred Investment Tax Credit	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
OPERATIONS & MAINTENANCE EXPENSES				
Distribution Expenses				
Operations Expenses				
(580) Operation Supervision & Engineering	DistOpExp-SUB	DistOpExp-PRI	DistOpExp-SEC	DistOpExp-CS
(581) Load Dispatching	DEM	DEM		
(582) Station Expenses	DEM	DEM		
(583) Overhead line expenses	OHLines-SUB	OHLines-PRI	OHLines-SEC	OHLines-CS
(584) Underground line expenses	UGLines-SUB	UGLines-PRI	UGLines-SEC	UGLines-CS
(585) Street lighting and signal system expenses				CUS
(586) Meter expenses				CUS
(588) Miscellaneous distribution expenses	DistOpExp-SUB	DistOpExp-PRI	DistOpExp-SEC	DistOpExp-CS
(589) Rents	DistOpExp-SUB	DistOpExp-PRI	DistOpExp-SEC	DistOpExp-CS
Maintenance Expense				
(590) Maintenance Supervision and Engineering	DistMtExp-SUB	DistMtExp-PRI	DistMtExp-SEC	DistMtExp-CS
(591) Maintenance of Structures	DistMtExp-SUB	DistMtExp-PRI	DistMtExp-SEC	DistMtExp-CS
(592) Maintenance of Station Equipment	DEM	DEM		
(593) Maintenance of Overhead Lines	OHLines-SUB	OHLines-PRI	OHLines-SEC	OHLines-CS
(594) Maintenance of underground lines	UGLines-SUB	UGLines-PRI	UGLines-SEC	UGLines-CS
(595) Maintenance of line transformers	DEM	368P	368S	
(596) Maintenance of street lighting and signal systems				CUS
(597) Maintenance of meters				CUS
(598) Maintenance of miscellaneous distribution p	DistMtExp-SUB	DistMtExp-PRI	DistMtExp-SEC	DistMtExp-CS
Customer Accounts and Services				
Meter Reading & Billing				CUS
Other-Direct to Other				CUS
Uncollectibles				CUS
Misc. Cust Serv and Info Exp				CUS
Customer Rebates & Incentives				CUS
Customer Assistance				CUS
Sales Expense				CUS
All Other Cust Accts & Services				CUS

The Potomac Edison Company (Maryland) Allocation to Customer Classes CLASSIFICATION FACTORS	Sub-Transmission	Primary	Secondary	Customer Service
Administrative & General Expense				
Administrative and General Salaries	NONAGLAB-SUB	NONAGLAB-PRI	NONAGLAB-SEC	NONAGLAB-CS
Outside Services	NONAGLAB-SUB	NONAGLAB-PRI	NONAGLAB-SEC	NONAGLAB-CS
Employee Benefits (Acct. 926)	NONAGLAB-SUB	NONAGLAB-PRI	NONAGLAB-SEC	NONAGLAB-CS
Regulatory Commission Expenses (Acct 928)	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
General Advertising Expense	OpExp-SUB	OpExp-PRI	OpExp-SEC	OpExp-CS
All Other O&M	NONAGLAB-SUB	NONAGLAB-PRI	NONAGLAB-SEC	NONAGLAB-CS
DEPRECIATION EXPENSE				
Depreciation Expense				
Distribution Plant DeprExp	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
General Plant DeprExp	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
Intangible Plant DeprExp	LABOR-SUB	LABOR-PRI	LABOR-SEC	LABOR-CS
Regulatory Debits and Credits				
MD EDIS	DEM	DEM	DEM	DEM
MD Electric Vehicle Program	EVREGASSET-SUB	EVREGASSET-PRI	EVREGASSET-SEC	EVREGASSET-CS
MD Conservation Voltage Reduction (CVR)	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Deferral of Rate Case Expenses	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
COVID-19	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
COVID-19 - Residential Adjustment	DISTPLT-SUB	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
TAXES				
Taxes Other than Income				
Distribution Payroll Taxes	DISTLAB-SUB	DISTLAB-PRI	DISTLAB-SEC	DISTLAB-CS
Customer Account Payroll Taxes	CUSTLAB-SUB	CUSTLAB-PRI	CUSTLAB-SEC	CUSTLAB-CS
A&G Payroll Taxes	AGLAB-SUB	AGLAB-PRI	AGLAB-SEC	AGLAB-CS
Gross Receipt Taxes	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Property Taxes	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Sales & Use Tax	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Montgomery County Fuel Energy	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Other Taxes	RB-SUB	RB-PRI	RB-SEC	RB-CS
Income Taxes				
State				
Federal				
Income Taxes Deferred - Net				
Allowance for Funds Used During Construction	CWIP-SUB	CWIP-PRI	CWIP-SEC	CWIP-CS
Interest on Customer Deposits	TOTPLT-SUB	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS

The Potomac Edison Company (Maryland) Summary of Allocators	Description	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
External Allocators								
12CP-GEN	Demand at Generation Level (ACP)	100.00%	61.11%	9.67%	0.25%	21.56%	7.35%	0.06%
12CP-SUB	Demand for Subtransmission (ACP)	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
1NCP-GEN	Demand at Generation Level (NCP)	100.00%	55.41%	12.35%	0.36%	22.64%	8.70%	0.54%
1NCP-PRI	Demand at Primary Level (NCP)	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
1NCP-SEC	Demand at Secondary Level (NCP)	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
1NCPxLT-SEC	Demand at Sec Level w/o St Ltg (NCP)	100.00%	65.17%	14.05%	0.38%	20.41%	0.00%	0.00%
Customers	Average Number of Customers	100.00%	88.04%	10.97%	0.11%	0.59%	0.00%	0.28%
Customers-PRI	Number of Customers at Primary Level	100.00%	88.05%	10.97%	0.11%	0.59%	0.00%	0.28%
Customers-SEC	Number of Customers at Secondary Level	100.00%	88.08%	10.96%	0.11%	0.56%	0.00%	0.28%
Revenue	Revenue from Sales (Distr)	100.00%	62.15%	18.38%	0.32%	14.42%	1.02%	3.70%
LatePayment	Late Payment Charges	100.00%	65.45%	17.55%	0.20%	15.14%	1.66%	0.00%
CUSxLT-SEC	Number of Secondary Cust Excl St. Lighting	100.00%	88.33%	10.99%	0.11%	0.56%	0.00%	0.00%
Meters	Meters	100.00%	59.39%	28.15%	0.62%	10.16%	1.67%	0.00%
StreetLighting	Direct to Street & Area Lighting	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Deposits	Customer Deposits	100.00%	54.64%	14.89%	0.00%	30.17%	0.00%	0.29%
SalesREV	Revenue from Sales	100.00%	63.76%	18.57%	0.32%	12.56%	0.78%	4.01%
MontCoFuel	Montgomery Co. Fuel Tax	100.00%	47.84%	18.22%	0.39%	32.12%	0.00%	1.43%
MeterReading	Acct. 902-903 Meter Reading	100.00%	85.45%	13.63%	0.18%	0.65%	0.00%	0.08%
Uncollectibles	Acct. 904 Uncollectibles	100.00%	99.92%	0.03%	0.00%	0.02%	0.02%	0.00%
CustServices	Misc. Cust Serv and Info Exp	100.00%	91.46%	7.68%	0.08%	0.26%	0.00%	0.51%
COVID	Covid Allocation	100.00%	83.01%	7.52%	0.13%	5.91%	3.01%	0.42%
Res-Direct	Residential Direct Allocation	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CustAssist	Acct. 908 Customer Assistance	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Internal Allocators								
TOTPLT-SUB-D		100.00%	63.07%	9.90%	0.26%	22.16%	4.54%	0.06%
TOTPLT-SUB-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-SUB-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-PRI-D		100.00%	61.44%	13.41%	0.39%	23.93%	0.23%	0.60%
TOTPLT-PRI-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-PRI-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-SEC-D		100.00%	64.81%	13.94%	0.37%	20.22%	0.04%	0.63%
TOTPLT-SEC-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-SEC-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-CS-D		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TOTPLT-CS-C		100.00%	62.32%	15.20%	0.28%	3.83%	0.60%	17.78%
TOTPLT-CS-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-SUB-D		100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
DISTPLT-SUB-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-SUB-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-PRI-D		100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
DISTPLT-PRI-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-PRI-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-SEC-D		100.00%	64.75%	13.95%	0.37%	20.28%	0.02%	0.63%
DISTPLT-SEC-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-SEC-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-CS-D		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLT-CS-C		100.00%	59.98%	14.84%	0.27%	3.86%	0.59%	20.47%
DISTPLT-CS-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-SUB-D		100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
GENPLT-SUB-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-SUB-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-PRI-D		100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
GENPLT-PRI-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-PRI-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-SEC-D		100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
GENPLT-SEC-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-SEC-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-CS-D		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENPLT-CS-C		100.00%	72.05%	16.84%	0.30%	3.62%	0.53%	6.65%
GENPLT-CS-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-SUB-D		100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
INTPLT-SUB-C		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-SUB-E		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

The Potomac Edison Company (Maryland) Summary of Allocators Description	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
INTPLT-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
INTPLT-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
INTPLT-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
INTPLT-CS-C	100.00%	72.05%	16.84%	0.30%	3.62%	0.53%	6.65%
INTPLT-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-SUB-D	100.00%	63.10%	10.93%	0.26%	21.09%	4.10%	0.53%
A&G-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-PRI-D	100.00%	61.64%	14.03%	0.39%	22.67%	0.28%	0.99%
A&G-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-SEC-D	100.00%	64.56%	14.86%	0.36%	18.78%	0.15%	1.28%
A&G-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A&G-CS-C	100.00%	71.80%	16.89%	0.30%	3.92%	0.54%	6.55%
A&G-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-SUB-D	100.00%	63.28%	9.81%	0.26%	21.97%	4.63%	0.06%
RB-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-PRI-D	100.00%	61.62%	13.37%	0.40%	23.76%	0.25%	0.60%
RB-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-SEC-D	100.00%	65.04%	13.91%	0.38%	19.99%	0.05%	0.63%
RB-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RB-CS-C	100.00%	62.57%	15.20%	0.28%	3.34%	0.62%	17.99%
RB-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-SUB-D	100.00%	63.07%	9.90%	0.26%	22.16%	4.54%	0.06%
CWIP-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-PRI-D	100.00%	61.44%	13.41%	0.39%	23.93%	0.23%	0.60%
CWIP-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-SEC-D	100.00%	64.81%	13.94%	0.37%	20.22%	0.04%	0.63%
CWIP-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CWIP-CS-C	100.00%	62.32%	15.20%	0.28%	3.83%	0.60%	17.78%
CWIP-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
LABOR-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
LABOR-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
LABOR-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
LABOR-CS-C	100.00%	72.05%	16.84%	0.30%	3.62%	0.53%	6.65%
LABOR-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
DISTLAB-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

The Potomac Edison Company (Maryland) Summary of Allocators Description	Total Company	Residential Service R	Small C & I Schedule C&G	Small C & I Schedule CA-CSH	Medium Power Schedule PH	Large Power Schedule PP	Street and Area Lighting ST LTNG
DISTLAB-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
DISTLAB-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
DISTLAB-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTLAB-CS-C	100.00%	61.97%	19.29%	0.38%	5.85%	0.93%	11.58%
DISTLAB-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SUB-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-PRI-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SEC-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTLAB-CS-C	100.00%	85.51%	13.58%	0.18%	0.65%	0.00%	0.08%
CUSTLAB-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
AGLAB-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
AGLAB-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
AGLAB-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AGLAB-CS-C	100.00%	72.05%	16.84%	0.30%	3.62%	0.53%	6.65%
AGLAB-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
NONAGLAB-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
NONAGLAB-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
NONAGLAB-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NONAGLAB-CS-C	100.00%	72.05%	16.84%	0.30%	3.62%	0.53%	6.65%
NONAGLAB-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-SUB-D	100.00%	63.28%	9.81%	0.26%	21.97%	4.63%	0.06%
RATEBASE-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-PRI-D	100.00%	61.62%	13.37%	0.40%	23.76%	0.25%	0.60%
RATEBASE-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-SEC-D	100.00%	65.04%	13.91%	0.38%	19.99%	0.05%	0.63%
RATEBASE-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
RATEBASE-CS-C	100.00%	62.57%	15.20%	0.28%	3.34%	0.62%	17.99%
RATEBASE-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
DistOpExp-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
DistOpExp-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
DistOpExp-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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DistOpExp-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistOpExp-CS-C	100.00%	61.19%	21.88%	0.45%	7.11%	1.15%	8.21%
DistOpExp-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
OHLines-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
OHLines-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
OHLines-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OHLines-CS-C	100.00%	88.33%	10.99%	0.11%	0.56%	0.00%	0.00%
OHLines-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
UGLines-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
UGLines-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
UGLines-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UGLines-CS-C	100.00%	88.33%	10.99%	0.11%	0.56%	0.00%	0.00%
UGLines-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
DistMtExp-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
DistMtExp-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
DistMtExp-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DistMtExp-CS-C	100.00%	74.19%	13.20%	0.20%	2.34%	0.32%	9.74%
DistMtExp-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-SUB-D	100.00%	63.01%	9.90%	0.26%	22.23%	4.54%	0.06%
OpExp-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-PRI-D	100.00%	61.37%	13.43%	0.40%	24.00%	0.21%	0.60%
OpExp-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-SEC-D	100.00%	64.76%	13.96%	0.37%	20.28%	0.00%	0.63%
OpExp-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OpExp-CS-C	100.00%	80.22%	13.17%	0.21%	2.10%	0.28%	4.02%
OpExp-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-SUB-D	100.00%	0.00%	26.77%	0.69%	60.10%	12.28%	0.17%
DISTPLTxRES-SUB-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-SUB-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-PRI-D	100.00%	0.00%	34.76%	1.02%	62.13%	0.55%	1.54%
DISTPLTxRES-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-PRI-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-SEC-D	100.00%	0.00%	39.59%	1.06%	57.53%	0.04%	1.78%
DISTPLTxRES-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-SEC-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DISTPLTxRES-CS-C	100.00%	0.00%	37.07%	0.68%	9.63%	1.49%	51.13%
DISTPLTxRES-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

The Potomac Edison Company (Maryland)
Summary of Classifiers

Classifier Description	Classifier Code	Total	- Demand	- Customer	- Commodity
External Classifiers					
Common					
Customer Factor	CUS	100.00%	0.00%	100.00%	0.00%
Demand Factor	DEM	100.00%	100.00%	0.00%	0.00%
Commodity Factor	COM	100.00%	0.00%	0.00%	100.00%
360 Primary Classifier	360P	100.00%	100.00%	0.00%	0.00%
360 Secondary Classifier	360S	100.00%	100.00%	0.00%	0.00%
364 Primary Classifier	364P	100.00%	100.00%	0.00%	0.00%
364 Secondary Classifier	364S	100.00%	100.00%	0.00%	0.00%
365 Primary Classifier	365P	100.00%	100.00%	0.00%	0.00%
365 Secondary Classifier	365S	100.00%	100.00%	0.00%	0.00%
366 Primary Classifier	366P	100.00%	100.00%	0.00%	0.00%
366 Secondary Classifier	366S	100.00%	100.00%	0.00%	0.00%
367 Primary Classifier	367P	100.00%	100.00%	0.00%	0.00%
367 Secondary Classifier	367S	100.00%	100.00%	0.00%	0.00%
368 Primary Classifier	368P	100.00%	100.00%	0.00%	0.00%
368 Secondary Classifier	368S	100.00%	100.00%	0.00%	0.00%
369 Classifier	369	100.00%	0.00%	100.00%	0.00%
Internal Classifiers - Derivation and Supporting Data					
TOTPLT					
Total Plant Subtransmission	TOTPLT-SUB	100.00%	100.00%	0.00%	0.00%
Total Plant Primary	TOTPLT-PRI	100.00%	100.00%	0.00%	0.00%
Total Plant Secondary	TOTPLT-SEC	100.00%	100.00%	0.00%	0.00%
Total Plant Customer	TOTPLT-CS	100.00%	0.00%	100.00%	0.00%
DISTPLT					
Dist. Plant Subtransmission	DISTPLT-SUB	100.00%	100.00%	0.00%	0.00%
Dist. Plant Primary	DISTPLT-PRI	100.00%	100.00%	0.00%	0.00%
Dist. Plant Secondary	DISTPLT-SEC	100.00%	100.00%	0.00%	0.00%
Dist. Plant Customer	DISTPLT-CS	100.00%	0.00%	100.00%	0.00%
GENPLT					
General Plant Subtransmission	GENPLT-SUB	100.00%	100.00%	0.00%	0.00%
General Plant Primary	GENPLT-PRI	100.00%	100.00%	0.00%	0.00%
General Plant Secondary	GENPLT-SEC	100.00%	100.00%	0.00%	0.00%
General Plant Customer	GENPLT-CS	100.00%	0.00%	100.00%	0.00%
INTPLT					
Intangible Plant Subtransmission	INTPLT-SUB	100.00%	100.00%	0.00%	0.00%
Intangible Plant Primary	INTPLT-PRI	100.00%	100.00%	0.00%	0.00%
Intangible Plant Secondary	INTPLT-SEC	100.00%	100.00%	0.00%	0.00%
Intangible Plant Customer	INTPLT-CS	100.00%	0.00%	100.00%	0.00%

The Potomac Edison Company (Maryland) Summary of Classifiers Classifier Description	Classifier Code	Total	- Demand	- Customer	- Commodity
A&G					
A&G Subtransmission	A&G-SUB	100.00%	100.00%	0.00%	0.00%
A&G Primary	A&G-PRI	100.00%	100.00%	0.00%	0.00%
A&G Secondary	A&G-SEC	100.00%	100.00%	0.00%	0.00%
A&G Customer	A&G-CS	100.00%	0.00%	100.00%	0.00%
RB					
Rate Base Subtransmission	RB-SUB	100.00%	100.00%	0.00%	0.00%
Rate Base Primary	RB-PRI	100.00%	100.00%	0.00%	0.00%
Rate Base Secondary	RB-SEC	100.00%	100.00%	0.00%	0.00%
Rate Base Customer	RB-CS	100.00%	0.00%	100.00%	0.00%
CWIP					
CWIP Subtransmission	CWIP-SUB	100.00%	100.00%	0.00%	0.00%
CWIP Primary	CWIP-PRI	100.00%	100.00%	0.00%	0.00%
CWIP Secondary	CWIP-SEC	100.00%	100.00%	0.00%	0.00%
CWIP Customer	CWIP-CS	100.00%	0.00%	100.00%	0.00%
LABOR					
LABOR Subtransmission	LABOR-SUB	100.00%	100.00%	0.00%	0.00%
LABOR Primary	LABOR-PRI	100.00%	100.00%	0.00%	0.00%
LABOR Secondary	LABOR-SEC	100.00%	100.00%	0.00%	0.00%
LABOR Customer	LABOR-CS	100.00%	0.00%	100.00%	0.00%
Dist Labor					
Dist Labor Subtransmission	DISTLAB-SUB	100.00%	100.00%	0.00%	0.00%
Dist Labor Primary	DISTLAB-PRI	100.00%	100.00%	0.00%	0.00%
Dist Labor Secondary	DISTLAB-SEC	100.00%	100.00%	0.00%	0.00%
Dist Labor Customer	DISTLAB-CS	100.00%	0.00%	100.00%	0.00%
Cust Labor					
Cust Labor Subtransmission	CUSTLAB-SUB	0.00%	0.00%	0.00%	0.00%
Cust Labor Primary	CUSTLAB-PRI	0.00%	0.00%	0.00%	0.00%
Cust Labor Secondary	CUSTLAB-SEC	0.00%	0.00%	0.00%	0.00%
Cust Labor Customer	CUSTLAB-CS	100.00%	0.00%	100.00%	0.00%
A&G Labor					
A&G Labor Subtransmission	AGLAB-SUB	100.00%	100.00%	0.00%	0.00%
A&G Labor Primary	AGLAB-PRI	100.00%	100.00%	0.00%	0.00%
A&G Labor Secondary	AGLAB-SEC	100.00%	100.00%	0.00%	0.00%
A&G Labor Customer	AGLAB-CS	100.00%	0.00%	100.00%	0.00%
Dist+Cust Labor					
Dist+Cust Labor Subtransmission	NONAGLAB-SUB	100.00%	100.00%	0.00%	0.00%
Dist+Cust Labor Primary	NONAGLAB-PRI	100.00%	100.00%	0.00%	0.00%
Dist+Cust Labor Secondary	NONAGLAB-SEC	100.00%	100.00%	0.00%	0.00%
Dist+Cust Labor Customer	NONAGLAB-CS	100.00%	0.00%	100.00%	0.00%
Rate Base					

The Potomac Edison Company (Maryland) Summary of Classifiers Classifier Description	Classifier Code	Total	- Demand	- Customer	- Commodity
Rate Base Subtransmission	RATEBASE-SUB	100.00%	100.00%	0.00%	0.00%
Rate Base Primary	RATEBASE-PRI	100.00%	100.00%	0.00%	0.00%
Rate Base Secondary	RATEBASE-SEC	100.00%	100.00%	0.00%	0.00%
Rate Base Customer	RATEBASE-CS	100.00%	0.00%	100.00%	0.00%
DistOpExp					
DistOpExp Subtransmission	DistOpExp-SUB	100.00%	100.00%	0.00%	0.00%
DistOpExp Primary	DistOpExp-PRI	100.00%	100.00%	0.00%	0.00%
DistOpExp Secondary	DistOpExp-SEC	100.00%	100.00%	0.00%	0.00%
DistOpExp Customer	DistOpExp-CS	100.00%	0.00%	100.00%	0.00%
Overhead Lines					
Overhead Lines Subtransmission	OHLines-SUB	100.00%	100.00%	0.00%	0.00%
Overhead Lines Primary	OHLines-PRI	100.00%	100.00%	0.00%	0.00%
Overhead Lines Secondary	OHLines-SEC	100.00%	100.00%	0.00%	0.00%
Overhead Lines Customer	OHLines-CS	100.00%	0.00%	100.00%	0.00%
U/G Lines					
U/G Lines Subtransmission	UGLines-SUB	100.00%	100.00%	0.00%	0.00%
U/G Lines Primary	UGLines-PRI	100.00%	100.00%	0.00%	0.00%
U/G Lines Secondary	UGLines-SEC	100.00%	100.00%	0.00%	0.00%
U/G Lines Customer	UGLines-CS	100.00%	0.00%	100.00%	0.00%
DistMtExp					
DistMtExp Subtransmission	DistMtExp-SUB	100.00%	100.00%	0.00%	0.00%
DistMtExp Primary	DistMtExp-PRI	100.00%	100.00%	0.00%	0.00%
DistMtExp Secondary	DistMtExp-SEC	100.00%	100.00%	0.00%	0.00%
DistMtExp Customer	DistMtExp-CS	100.00%	0.00%	100.00%	0.00%
Operating Expenses					
Operating Expenses Subtransmission	OpExp-SUB	100.00%	100.00%	0.00%	0.00%
Operating Expenses Primary	OpExp-PRI	100.00%	100.00%	0.00%	0.00%
Operating Expenses Secondary	OpExp-SEC	100.00%	100.00%	0.00%	0.00%
Operating Expenses Customer	OpExp-CS	100.00%	0.00%	100.00%	0.00%
Dist. Plant excl. Residential					
Dist. Plant excl. Res Subtransmission	DISTPLTxRES-SUB	100.00%	100.00%	0.00%	0.00%
Dist. Plant excl. Res Primary	DISTPLTxRES-PRI	100.00%	100.00%	0.00%	0.00%
Dist. Plant excl. Res Secondary	DISTPLTxRES-SEC	100.00%	100.00%	0.00%	0.00%
Dist. Plant excl. Res Customer	DISTPLTxRES-CS	100.00%	0.00%	100.00%	0.00%

The Potomac Edison Company (Maryland) Functional Factors	Code	Total	Sub-Transmission	Primary	Secondary	Customer Service
EXTERNAL FUNCTIONAL FACTORS						
Customer Service Only	CUSTSERVICE	100.0%	0.0%	0.0%	0.0%	100.0%
Primary Distribution Only	PRIMARY	100.0%	0.0%	100.0%	0.0%	0.0%
Secondary Distribution Only	SECONDARY	100.0%	0.0%	0.0%	100.0%	0.0%
Subtransmission Only	SUBTRANSMISSION	100.0%	100.0%	0.0%	0.0%	0.0%
Account 360 Land and Land Rights	ACC360	100.0%	6.9%	54.5%	38.6%	0.0%
Account 361 Structures and Improvements	ACC361	100.0%	0.1%	99.9%	0.0%	0.0%
Account 362 Station Equipment	ACC362	100.0%	0.5%	99.5%	0.0%	0.0%
Account 364 Poles, Towers & Fixtures	ACC364	100.0%	29.5%	4.0%	66.6%	0.0%
Account 365 Overhead Conductors & Devices	ACC365	100.0%	42.8%	3.0%	54.2%	0.0%
Account 366 Underground Conduit	ACC366	100.0%	27.8%	3.7%	68.6%	0.0%
Account 367 Underground Conductors & Device	ACC367	100.0%	30.3%	1.5%	68.2%	0.0%
Account 368 Transformers	ACC368	100.0%	0.0%	0.2%	99.8%	0.0%
INTERNAL FUNCTIONAL FACTORS						
Rate Base Factor	RB	100.0%	19.2%	16.9%	49.5%	14.4%
Total Distribution Plant Factor	DISTPLT	100.0%	19.3%	17.1%	51.5%	12.1%
Total Utility Plant Factor	TOTPLT	100.0%	19.2%	17.0%	49.9%	14.0%
Total General Plant Factor	GENPLT	100.0%	17.5%	15.7%	25.9%	40.9%
Overhead and Service Lines Factor	OHLINES	100.0%	35.3%	2.5%	44.7%	17.4%
Underground Lines Factor	UG LINES	100.0%	28.3%	1.8%	64.7%	5.2%
Distribution Operating Expenses Factor	DISTOPEXP	100.0%	22.4%	5.0%	39.0%	33.7%
Distribution Maintenance Expenses Factor	DISTMTEXP	100.0%	29.2%	12.6%	38.5%	19.8%
Labor Expenses	LABOR	100.0%	17.5%	15.7%	25.9%	40.9%
Dist Labor Expenses	DISTLAB	100.0%	21.2%	19.1%	31.4%	28.4%
Customer Labor Expenses	CUSTLAB	100.0%	0.0%	0.0%	0.0%	100.0%
A&G Labor Expenses	AGLAB	100.0%	17.5%	15.7%	25.9%	40.9%
Non-A&G Labor Expenses	NONAGLAB	100.0%	17.5%	15.7%	25.9%	40.9%
Total Operating Expenses excl. A&G Factor	OPEXP	100.0%	20.8%	7.9%	29.4%	41.9%
INTERNAL FUNCTIONAL FACTORS DERIVATION						
Total Distribution Plant		1,370,353,215	264,958,327	233,684,367	705,760,924	165,949,597
Total Distribution Plant Factor	DISTPLT	100.0%	19.3%	17.1%	51.5%	12.1%
Total General Plant		94,864,996	16,571,017	14,919,176	24,552,383	38,822,420
Total General Plant Factor	GENPLT	100.0%	17.5%	15.7%	25.9%	40.9%
Total Utility Plant		1,474,004,730	283,228,221	250,101,895	734,838,550	205,836,063
Total Utility Plant Factor	TOTPLT	100.0%	19.2%	17.0%	49.9%	14.0%
Overhead and Service Lines (Accts. 365, 369OH)		296,947,998	104,904,585	7,476,890	132,766,709	51,799,814
Overhead and Service Lines Factor	OHLINES	100.0%	35.3%	2.5%	44.7%	17.4%
Underground Lines (Acct. 366-367, 369UG)		410,866,051	116,371,686	7,422,638	265,820,427	21,251,299
Underground Lines Factor	UG LINES	100.0%	28.3%	1.8%	64.7%	5.2%
Distribution Operating Expenses		3,869,177	865,012	191,581	1,508,516	1,304,067
Distribution Operating Expenses Factor	DISTOPEXP	100.0%	22.4%	5.0%	39.0%	33.7%
Distribution Maintenance Expenses		24,178,759	7,055,010	3,040,287	9,302,164	4,781,299
Distribution Maintenance Expenses Factor	DISTMTEXP	100.0%	29.2%	12.6%	38.5%	19.8%
Total Operating Expenses excl. A&G		44,385,845	9,213,081	3,527,856	13,046,172	18,598,735
Total Operating Expenses excl. A&G Factor	OPEXP	100.0%	20.8%	7.9%	29.4%	41.9%

The Potomac Edison Company (Maryland) Functional Factors	Code	Total	Sub-Transmission	Primary	Secondary	Customer Service
Revenue Requirement						
Total Rate Base		718,525,219	137,876,780	121,783,036	355,642,109	103,223,294
Required Return on Rate Base		7.54%	7.54%	7.54%	7.54%	7.54%
Required Net Income		54,188,230	10,398,102	9,184,378	26,821,072	7,784,678
O&M Expenses		56,655,385	11,382,575	5,471,518	16,563,069	23,238,223
Depreciation & Amortization		33,822,024	6,484,474	5,728,537	16,663,941	4,945,072
Regulatory Debits and Credits		1,288,352	249,300	219,841	666,228	152,984
Taxes Other than Income		30,607,318	5,849,161	5,167,356	15,026,790	4,564,010
Total Expenses		122,373,079	23,965,511	16,587,252	48,920,028	32,900,289
Allowance for Funds Used During Construction		2,609,343	501,382	442,740	1,300,841	364,379
Interest on Customer Deposits		(17,180)	(3,301)	(2,915)	(8,565)	(2,399)
Income Taxes		10,884,154	2,088,545	1,844,758	5,387,234	1,563,617
Revenue Requirement		190,037,627	36,950,239	28,056,213	82,420,611	42,610,564

PE 2023 Base Rate Case Filing
PE Operating Company Peaks - Potomac Edison Maryland
January 2019 - December 2019

Rate Class Coincident Monthly Peaks
At Generation Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/31/2019	8	1,681,432	1,134,896	151,826	5,749	304,066	83,304	1,590
2/1/2019	8	1,474,898	926,554	130,192	5,653	295,979	116,521	-
3/6/2019	7	1,355,177	861,906	125,846	4,639	255,353	106,470	964
4/1/2019	8	1,087,826	673,856	92,335	2,710	224,109	94,816	-
5/28/2019	18	1,229,482	600,894	116,633	2,703	391,570	117,682	-
6/28/2019	17	1,255,981	677,024	138,431	3,331	332,287	104,907	-
7/21/2019	18	1,439,123	923,396	146,193	3,501	284,778	81,255	-
8/19/2019	18	1,325,301	764,553	135,708	2,954	313,998	108,088	-
9/4/2019	18	1,258,278	740,193	115,539	2,729	300,290	99,528	-
10/2/2019	17	1,185,141	500,848	175,475	4,290	382,565	121,963	-
11/13/2019	8	1,158,620	727,807	106,022	3,251	221,274	100,267	-
12/20/2019	8	1,337,163	859,872	132,459	4,897	237,004	101,741	1,191
	Average 12 CP	1,315,702	782,650	130,555	3,867	295,273	103,045	312
	% ACP Allocator (Gen)	100.00%	59.49%	9.92%	0.29%	22.44%	7.83%	0.02%

Rate Class Coincident Monthly Peaks
At Sub-transmission Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/31/2019	8	1,628,174	1,134,896	151,826	5,749	283,899	50,214	1,590
2/1/2019	8	1,423,777	926,554	130,192	5,653	268,325	93,053	-
3/6/2019	7	1,292,830	861,906	125,846	4,639	231,279	68,197	964
4/1/2019	8	1,029,946	673,856	92,335	2,710	203,626	57,419	-
5/28/2019	18	1,143,959	600,894	116,633	2,703	352,574	71,155	-
6/28/2019	17	1,188,095	677,024	138,431	3,331	302,327	66,981	-
7/21/2019	18	1,403,219	923,396	146,193	3,501	278,413	51,715	-
8/19/2019	18	1,283,990	764,553	131,476	2,954	313,998	71,008	-
9/4/2019	18	1,219,915	740,193	112,001	2,729	300,290	64,703	-
10/2/2019	17	1,132,848	500,848	169,901	4,290	382,565	75,244	-
11/13/2019	8	1,116,807	727,807	102,598	3,251	221,274	61,878	-
12/20/2019	8	1,294,764	859,872	128,003	4,897	237,004	63,798	1,191
	Average 12 CP	1,263,194	782,650	128,786	3,867	281,298	66,280	312
	% ACP Allocator (Sub)	100.00%	61.96%	10.20%	0.31%	22.27%	5.25%	0.02%

Rate Class Coincident Monthly Peaks
At Primary Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/31/2019	8	1,570,408	1,134,896	151,407	5,749	274,967	1,799	1,590
2/1/2019	8	1,326,208	926,554	129,874	5,653	259,697	4,429	-
3/6/2019	7	1,219,775	861,906	125,483	4,639	223,894	2,890	964
4/1/2019	8	968,681	673,856	92,031	2,710	197,131	2,953	-
5/28/2019	18	1,064,665	600,894	116,190	2,703	341,380	3,498	-
6/28/2019	17	1,114,910	677,024	137,979	3,331	293,026	3,550	-
7/21/2019	18	1,346,333	923,396	145,831	3,501	270,460	3,145	-
8/19/2019	18	1,207,423	764,553	131,117	2,954	304,744	4,055	-
9/4/2019	18	1,149,907	740,193	111,684	2,729	291,606	3,696	-
10/2/2019	17	1,049,695	500,848	169,458	4,290	371,183	3,916	-
11/13/2019	8	1,050,746	727,807	102,290	3,251	214,420	2,979	-
12/20/2019	8	1,223,870	859,872	127,654	4,897	227,574	2,683	1,191
	Average 12 CP	1,191,052	782,650	128,416	3,867	272,507	3,299	312
	% ACP Allocator (Pri)	100.00%	65.71%	10.78%	0.32%	22.88%	0.28%	0.03%

Rate Class Coincident Monthly Peaks
At Secondary Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/31/2019	8	1,508,966	1,134,896	149,744	5,231	217,506	-	1,590
2/1/2019	8	1,265,809	926,554	128,381	5,147	205,727	-	-
3/6/2019	7	1,168,735	861,906	124,263	4,192	177,410	-	964
4/1/2019	8	923,310	673,856	91,098	2,364	155,993	-	-
5/28/2019	18	990,640	600,894	114,843	2,305	272,599	-	-
6/28/2019	17	1,053,404	677,024	136,529	2,880	236,971	-	-
7/21/2019	18	1,290,584	923,396	144,472	3,006	219,709	-	-
8/19/2019	18	1,144,108	764,553	129,895	2,526	247,134	-	-
9/4/2019	18	1,090,957	740,193	110,650	2,324	237,790	-	-
10/2/2019	17	972,551	500,848	167,471	3,569	300,662	-	-
11/13/2019	8	1,003,580	727,807	100,958	2,810	172,005	-	-
12/20/2019	8	1,172,848	859,872	126,190	4,342	181,254	-	1,191
	Average 12 CP	1,132,124	782,650	127,041	3,391	218,730	-	312
	% ACP Allocator (Sec)	100.00%	69.13%	11.22%	0.30%	19.32%	0.00%	0.03%

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Rate Class Coincident Monthly Peaks
At Generation Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/22/2020	8	1,343,948	850,656	137,571	4,353	259,699	89,923	1,746
2/15/2020	8	1,295,673	903,826	99,629	3,644	206,564	82,010	-
3/1/2020	8	1,058,995	689,888	94,814	2,986	190,014	81,294	-
4/17/2020	8	898,931	588,419	77,442	2,187	155,521	75,362	-
5/29/2020	14	1,060,603	427,410	140,904	3,593	360,221	128,475	-
6/10/2020	17	1,244,677	675,320	141,843	2,797	317,159	107,558	-
7/20/2020	17	1,420,327	832,746	160,596	3,456	317,227	106,303	-
8/12/2020	17	1,323,681	723,848	163,373	3,382	325,817	107,262	-
9/10/2020	18	1,113,265	613,173	103,881	2,329	295,455	98,427	-
10/31/2020	9	858,675	560,283	65,609	1,346	151,669	79,768	-
11/19/2020	8	1,066,543	676,661	89,613	2,434	197,260	100,574	-
12/16/2020	18	1,270,938	773,688	142,169	4,167	257,694	88,795	4,424
	Average 12 CP	1,163,021	692,993	118,120	3,056	252,858	95,479	514
	% ACP Allocator (Gen)	100.00%	59.59%	10.16%	0.26%	21.74%	8.21%	0.04%

Rate Class Coincident Monthly Peaks
At Sub-transmission Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/22/2020	8	1,303,150	850,656	133,607	4,353	259,699	53,090	1,746
2/15/2020	8	1,272,157	903,826	96,967	3,644	206,564	61,155	-
3/1/2020	8	1,029,741	689,888	91,892	2,986	190,014	54,961	-
4/17/2020	8	866,662	588,419	75,260	2,187	155,521	45,275	-
5/29/2020	14	999,633	427,410	137,779	3,593	360,221	70,630	-
6/10/2020	17	1,198,654	675,320	139,240	2,797	317,159	64,138	-
7/20/2020	17	1,377,311	832,746	158,448	3,456	317,227	65,435	-
8/12/2020	17	1,279,985	723,848	161,419	3,382	325,817	65,520	-
9/10/2020	18	1,076,863	613,173	102,431	2,329	295,455	63,475	-
10/31/2020	9	829,647	560,283	64,545	1,346	151,669	51,803	-
11/19/2020	8	1,023,511	676,661	87,716	2,434	197,260	59,438	-
12/16/2020	18	1,230,507	773,688	139,995	4,167	257,694	50,539	4,424
	Average 12 CP	1,123,985	692,993	115,775	3,056	252,858	58,788	514
	% ACP Allocator (Sub)	100.00%	61.66%	10.30%	0.27%	22.50%	5.23%	0.05%

Rate Class Coincident Monthly Peaks
At Primary Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/22/2020	8	1,243,541	850,656	133,260	4,353	251,311	2,216	1,746
2/15/2020	8	1,206,951	903,826	96,640	3,644	199,918	2,923	-
3/1/2020	8	970,750	689,888	91,617	2,986	183,821	2,438	-
4/17/2020	8	817,735	588,419	75,039	2,187	150,263	1,827	-
5/29/2020	14	918,571	427,410	137,318	3,593	347,624	2,625	-
6/10/2020	17	1,126,323	675,320	138,824	2,797	306,424	2,959	-
7/20/2020	17	1,305,339	832,746	157,984	3,456	307,422	3,732	-
8/12/2020	17	1,204,817	723,848	161,007	3,382	312,815	3,765	-
9/10/2020	18	1,008,114	613,173	102,224	2,329	286,369	4,018	-
10/31/2020	9	774,914	560,283	64,347	1,346	146,679	2,260	-
11/19/2020	8	960,900	676,661	87,388	2,434	191,224	3,193	-
12/16/2020	18	1,173,724	773,688	139,411	4,167	249,708	2,326	4,424
	Average 12 CP	1,059,307	692,993	115,422	3,056	244,465	2,857	514
	% ACP Allocator (Pri)	100.00%	65.42%	10.90%	0.29%	23.08%	0.27%	0.05%

Rate Class Coincident Monthly Peaks
At Secondary Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/22/2020	8	1,187,869	850,656	132,118	3,904	199,445	-	1,746
2/15/2020	8	1,161,317	903,826	95,347	3,305	158,839	-	-
3/1/2020	8	929,305	689,888	90,396	2,671	146,350	-	-
4/17/2020	8	783,861	588,419	74,122	1,883	119,437	-	-
5/29/2020	14	840,224	427,410	135,999	2,968	273,848	-	-
6/10/2020	17	1,059,936	675,320	137,356	2,256	245,005	-	-
7/20/2020	17	1,240,156	832,746	156,556	2,886	247,968	-	-
8/12/2020	17	1,140,548	723,848	159,832	2,820	254,048	-	-
9/10/2020	18	948,423	613,173	101,280	1,968	232,002	-	-
10/31/2020	9	742,888	560,283	63,484	1,082	118,039	-	-
11/19/2020	8	916,466	676,661	85,904	2,048	151,853	-	-
12/16/2020	18	1,115,869	773,688	137,502	3,569	196,686	-	4,424
	Average 12 CP	1,005,572	692,993	114,158	2,613	195,293	-	514
	% ACP Allocator (Sec)	100.00%	68.92%	11.35%	0.26%	19.42%	0.00%	0.05%

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Rate Class Coincident Monthly Peaks
At Generation Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/29/2021	8	1,269,576	816,372	132,118	4,927	245,526	68,859	1,775
2/8/2021	8	1,272,091	833,263	120,302	4,192	224,034	90,300	-
3/8/2021	7	1,166,644	770,928	112,598	3,769	197,069	81,472	809
4/2/2021	8	1,068,081	697,785	94,179	2,520	188,900	84,696	-
5/26/2021	15	1,112,704	433,906	164,558	3,681	393,172	117,386	-
6/29/2021	18	1,365,845	837,464	119,677	2,166	307,849	98,689	-
7/13/2021	18	1,377,013	828,179	131,199	2,761	315,144	99,730	-
8/12/2021	18	1,432,400	882,333	152,221	3,182	297,293	97,371	-
9/15/2021	17	1,200,727	603,700	158,687	3,581	334,056	100,704	-
10/4/2021	17	997,587	351,811	149,024	3,349	369,501	123,903	-
11/24/2021	8	1,131,849	704,389	100,706	2,427	221,176	103,150	-
12/20/2021	8	1,229,401	784,395	118,903	3,814	222,746	98,485	1,059
	Average 12 CP	1,218,660	712,044	129,514	3,364	276,372	97,062	304
	% ACP Allocator (Gen)	100.00%	58.43%	10.63%	0.28%	22.68%	7.96%	0.02%

Rate Class Coincident Monthly Peaks
At Sub-transmission Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/29/2021	8	1,238,666	816,372	130,155	4,927	245,526	39,911	1,775
2/8/2021	8	1,248,041	833,263	118,589	4,192	224,034	67,963	-
3/8/2021	7	1,134,266	770,928	110,921	3,769	197,069	50,771	809
4/2/2021	8	1,030,500	697,785	92,675	2,520	188,900	48,618	-
5/26/2021	15	1,060,188	433,906	162,020	3,681	393,172	67,408	-
6/29/2021	18	1,323,247	837,464	118,185	2,166	307,849	57,583	-
7/13/2021	18	1,333,163	828,179	129,822	2,761	315,144	57,257	-
8/12/2021	18	1,393,307	882,333	150,475	3,182	297,293	60,024	-
9/15/2021	17	1,161,641	603,700	156,978	3,581	334,056	63,327	-
10/4/2021	17	945,813	351,811	147,155	3,349	369,501	73,997	-
11/24/2021	8	1,089,273	704,389	99,361	2,427	221,176	61,918	-
12/20/2021	8	1,186,763	784,395	117,013	3,814	222,746	57,737	1,059
	Average 12 CP	1,178,739	712,044	127,779	3,364	276,372	58,876	304
	% ACP Allocator (Sub)	100.00%	60.41%	10.84%	0.29%	23.45%	4.99%	0.03%

Rate Class Coincident Monthly Peaks
At Primary Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/29/2021	8	1,192,169	816,372	129,498	4,927	237,660	1,939	1,775
2/8/2021	8	1,175,792	833,263	117,908	4,192	216,707	3,722	-
3/8/2021	7	1,078,523	770,928	109,803	3,769	190,726	2,487	809
4/2/2021	8	976,911	697,785	91,490	2,520	182,632	2,482	-
5/26/2021	15	975,841	433,906	160,459	3,681	374,414	3,380	-
6/29/2021	18	1,257,468	837,464	117,700	2,166	298,134	2,004	-
7/13/2021	18	1,267,786	828,179	129,325	2,761	305,367	2,153	-
8/12/2021	18	1,326,250	882,333	150,030	3,182	288,333	2,372	-
9/15/2021	17	1,089,514	603,700	156,503	3,581	323,155	2,576	-
10/4/2021	17	861,301	351,811	146,633	3,349	357,107	2,401	-
11/24/2021	8	1,021,061	704,389	98,960	2,427	213,393	1,891	-
12/20/2021	8	1,122,654	784,395	116,617	3,814	215,108	1,663	1,059
	Average 12 CP	1,112,106	712,044	127,077	3,364	266,895	2,423	304
	% ACP Allocator (Pri)	100.00%	64.03%	11.43%	0.30%	24.00%	0.22%	0.03%

Rate Class Coincident Monthly Peaks
At Secondary Voltage Level

Date	Hour (HE EST)	Monthly Peak (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
1/29/2021	8	1,137,163	816,372	127,922	4,442	186,653	-	1,775
2/8/2021	8	1,123,877	833,263	116,588	3,788	170,237	-	-
3/8/2021	7	1,033,151	770,928	108,285	3,343	149,787	-	809
4/2/2021	8	932,724	697,785	90,139	2,174	142,626	-	-
5/26/2021	15	893,504	433,906	157,887	3,091	298,620	-	-
6/29/2021	18	1,194,474	837,464	116,056	1,751	239,203	-	-
7/13/2021	18	1,203,940	828,179	127,778	2,329	245,654	-	-
8/12/2021	18	1,263,700	882,333	148,225	2,677	230,466	-	-
9/15/2021	17	1,021,565	603,700	154,427	3,015	260,424	-	-
10/4/2021	17	783,858	351,811	144,272	2,783	284,993	-	-
11/24/2021	8	973,445	704,389	97,340	2,054	169,662	-	-
12/20/2021	8	1,072,475	784,395	114,710	3,385	168,926	-	1,059
	Average 12 CP	1,052,823	712,044	125,302	2,903	212,271	-	304
	% ACP Allocator (Sec)	100.00%	67.63%	11.90%	0.28%	20.16%	0.00%	0.03%

PE 2023 Base Rate Case Filing
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Rate Class Non-Coincident Monthly Peaks
At Generation Voltage Level

Month	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,769,876	1,134,896	193,078	7,313	340,683	88,381	5,525
February	1,656,387	985,981	174,538	7,579	360,334	122,697	5,258
March	1,528,978	861,906	155,462	5,727	364,580	131,839	9,464
April	1,295,391	673,856	126,964	3,726	360,414	121,591	8,840
May	1,443,822	668,454	167,529	3,881	441,297	150,673	11,989
June	1,410,166	715,770	168,878	4,061	385,054	126,741	9,662
July	1,673,871	923,396	210,202	5,033	399,289	126,397	9,554
August	1,501,534	815,550	202,912	4,417	342,056	127,444	9,155
September	1,704,229	763,100	284,252	6,714	388,584	248,826	12,753
October	1,669,144	744,897	292,848	7,161	460,552	154,816	8,870
November	1,317,850	727,807	135,199	4,143	310,097	132,719	7,887
December	1,466,576	872,917	162,719	6,017	288,472	130,004	6,448
Max NCP	2,157,454	1,134,896	292,848	7,579	460,552	248,826	12,753
% NCP Allocator (Gen)	100.00%	52.60%	13.57%	0.35%	21.35%	11.53%	0.59%

Rate Class Non-Coincident Monthly Peaks
At Sub-transmission Voltage Level

Date	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,683,404	1,134,896	193,078	7,313	340,683	1,909	5,525
February	1,538,354	985,981	174,538	7,579	360,334	4,664	5,258
March	1,400,718	861,906	155,462	5,727	364,580	3,578	9,464
April	1,177,587	673,856	126,964	3,726	360,414	3,787	8,840
May	1,297,628	668,454	167,529	3,881	441,297	4,479	11,989
June	1,287,713	715,770	168,878	4,061	385,054	4,289	9,662
July	1,552,365	923,396	210,202	5,033	399,289	4,892	9,554
August	1,372,546	815,550	196,586	4,417	342,056	4,781	9,155
September	1,455,941	763,100	275,549	6,714	388,584	9,241	12,753
October	1,509,996	744,897	283,546	7,161	460,552	4,971	8,870
November	1,184,711	727,807	130,835	4,143	310,097	3,943	7,887
December	1,334,526	872,917	157,245	6,017	288,472	3,429	6,448
Max NCP	1,908,567	1,134,896	283,546	7,579	460,552	9,241	12,753
% NCP Allocator (Sub)	100.00%	59.46%	14.86%	0.40%	24.13%	0.48%	0.67%

Rate Class Non-Coincident Monthly Peaks
At Primary Voltage Level

Date	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,672,863	1,134,896	192,545	7,313	330,675	1,909	5,525
February	1,527,424	985,981	174,113	7,579	349,830	4,664	5,258
March	1,389,726	861,906	155,014	5,727	354,037	3,578	9,464
April	1,166,724	673,856	126,547	3,726	349,969	3,787	8,840
May	1,284,378	668,454	166,894	3,881	428,682	4,479	11,989
June	1,276,371	715,770	168,327	4,061	374,263	4,289	9,662
July	1,540,690	923,396	209,681	5,033	388,134	4,892	9,554
August	1,361,923	815,550	196,049	4,417	331,971	4,781	9,155
September	1,443,912	763,100	274,768	6,714	377,337	9,241	12,753
October	1,495,546	744,897	282,806	7,161	446,842	4,971	8,870
November	1,174,713	727,807	130,442	4,143	300,492	3,943	7,887
December	1,322,499	872,917	156,816	6,017	276,874	3,429	6,448
Max NCP	1,894,117	1,134,896	282,806	7,579	446,842	9,241	12,753
% NCP Allocator (Pri)	100.00%	59.92%	14.93%	0.40%	23.59%	0.49%	0.67%

Rate Class Non-Coincident Monthly Peaks
At Secondary Voltage Level

Date	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,583,111	1,134,896	190,429	6,653	243,699	1,909	5,525
February	1,425,373	985,981	172,111	6,901	250,459	4,664	5,258
March	1,286,929	861,906	153,507	5,176	253,298	3,578	9,464
April	1,065,865	673,856	125,263	3,250	250,869	3,787	8,840
May	1,160,407	668,454	164,959	3,309	307,217	4,479	11,989
June	1,174,383	715,770	166,560	3,510	274,592	4,289	9,662
July	1,457,945	923,396	207,729	4,320	308,053	4,892	9,554
August	1,296,700	815,550	194,223	3,777	269,213	4,781	9,155
September	1,370,737	763,100	272,224	5,718	307,700	9,241	12,753
October	1,406,131	744,897	279,489	5,958	361,947	4,971	8,870
November	1,113,013	727,807	128,746	3,581	241,051	3,943	7,887
December	1,263,664	872,917	155,017	5,335	220,520	3,429	6,448
Max NCP	1,805,227	1,134,896	279,489	6,901	361,947	9,241	12,753
% NCP Allocator (Sec)	100.00%	62.87%	15.48%	0.38%	20.05%	0.51%	0.71%

PE 2023 Base Rate Case Filing
PE Operating Company Peaks - Potomac Edison Maryland
January 2020 - December 2020

Rate Class Non-Coincident Monthly Peaks
At Generation Voltage Level

Month	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,443,309	850,656	195,817	6,198	290,344	93,333	6,961
February	1,456,958	903,826	148,509	5,431	289,627	101,564	8,001
March	1,343,800	703,536	162,126	5,103	319,951	144,294	8,789
April	1,129,162	552,732	136,155	3,845	296,523	128,400	11,508
May	1,280,701	596,494	153,669	3,920	372,670	142,986	10,961
June	1,562,943	735,880	204,161	4,024	444,523	162,780	11,575
July	1,673,569	879,427	222,022	4,777	410,462	147,015	9,865
August	1,560,001	821,341	205,414	4,251	386,124	133,202	9,669
September	1,247,347	608,272	164,035	3,677	338,034	125,734	7,595
October	1,128,731	517,443	135,192	2,774	331,974	133,882	7,466
November	1,222,907	626,185	132,296	3,591	320,778	131,687	8,370
December	1,476,736	857,463	168,359	4,931	310,237	128,607	7,139
Max NCP	1,750,923	903,826	222,022	6,198	444,523	162,780	11,575
% NCP Allocator (Gen)	100.00%	51.62%	12.68%	0.35%	25.39%	9.30%	0.66%

Rate Class Non-Coincident Monthly Peaks
At Sub-transmission Voltage Level

Date	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,399,434	850,656	190,173	6,198	290,344	55,103	6,961
February	1,427,163	903,826	144,542	5,431	289,627	75,736	8,001
March	1,292,066	703,536	157,133	5,103	319,951	97,554	8,789
April	1,074,064	552,732	132,318	3,845	296,523	77,138	11,508
May	1,212,913	596,494	150,260	3,920	372,670	78,608	10,961
June	1,493,486	735,880	200,416	4,024	444,523	97,068	11,575
July	1,614,080	879,427	219,053	4,777	410,462	90,495	9,865
August	1,505,707	821,341	202,957	4,251	386,124	81,365	9,669
September	1,200,410	608,272	161,746	3,677	338,034	81,085	7,595
October	1,079,603	517,443	133,000	2,774	331,974	86,946	7,466
November	1,166,248	626,185	129,498	3,591	320,778	77,826	8,370
December	1,418,754	857,463	165,786	4,931	310,237	73,198	7,139
Max NCP	1,682,728	903,826	219,053	6,198	444,523	97,554	11,575
% NCP Allocator (Sub)	100.00%	53.71%	13.02%	0.37%	26.42%	5.80%	0.69%

Rate Class Non-Coincident Monthly Peaks
At Primary Voltage Level

Date	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,336,759	850,656	189,678	6,198	280,966	2,300	6,961
February	1,345,241	903,826	144,055	5,431	280,309	3,620	8,001
March	1,187,943	703,536	156,663	5,103	309,524	4,328	8,789
April	989,624	552,732	131,929	3,845	286,498	3,113	11,508
May	1,123,692	596,494	149,757	3,920	359,638	2,922	10,961
June	1,385,251	735,880	199,817	4,024	429,478	4,478	11,575
July	1,515,418	879,427	218,412	4,777	397,776	5,161	9,865
August	1,412,929	821,341	202,439	4,251	370,553	4,676	9,669
September	1,113,702	608,272	161,420	3,677	327,604	5,133	7,595
October	985,094	517,443	132,591	2,774	321,028	3,792	7,466
November	1,082,301	626,185	129,014	3,591	310,962	4,180	8,370
December	1,338,620	857,463	165,095	4,931	300,622	3,369	7,139
Max NCP	1,574,649	903,826	218,412	6,198	429,478	5,161	11,575
% NCP Allocator (Pri)	100.00%	57.40%	13.87%	0.39%	27.27%	0.33%	0.74%

Rate Class Non-Coincident Monthly Peaks
At Secondary Voltage Level

Date	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,274,209	850,656	188,053	5,558	222,980	-	6,961
February	1,281,591	903,826	142,127	4,926	222,711	-	8,001
March	1,117,896	703,536	154,577	4,565	246,429	-	8,789
April	925,592	552,732	130,317	3,311	227,724	-	11,508
May	1,042,322	596,494	148,317	3,238	283,312	-	10,961
June	1,291,798	735,880	197,705	3,246	343,393	-	11,575
July	1,430,567	879,427	216,438	3,989	320,848	-	9,865
August	1,336,455	821,341	200,963	3,545	300,938	-	9,669
September	1,044,313	608,272	159,929	3,107	265,409	-	7,595
October	916,297	517,443	130,813	2,230	258,346	-	7,466
November	1,011,338	626,185	126,824	3,021	246,938	-	8,370
December	1,268,451	857,463	162,835	4,224	236,790	-	7,139
Max NCP	1,480,790	903,826	216,438	5,558	343,393	-	11,575
% NCP Allocator (Sec)	100.00%	61.04%	14.62%	0.38%	23.19%	0.00%	0.78%

PE 2023 Base Rate Case Filing
PE Operating Company Peaks - Potomac Edison Maryland
January 2021 - December 2021

Rate Class Non-Coincident Monthly Peaks
At Generation Voltage Level

Month	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,388,777	822,095	173,879	6,485	308,607	71,743	5,968
February	1,444,670	876,096	166,592	5,806	287,191	102,544	6,442
March	1,387,268	770,928	151,169	5,058	348,368	104,117	7,628
April	1,336,405	697,785	142,438	3,811	356,731	125,921	9,718
May	1,328,057	610,606	166,061	3,715	403,648	134,631	9,395
June	1,626,616	876,028	195,760	3,537	400,141	141,159	9,991
July	1,591,925	864,726	206,520	4,347	380,577	126,404	9,351
August	1,650,982	908,055	209,299	4,374	386,409	134,814	8,030
September	1,375,605	703,151	179,017	4,038	362,163	119,101	8,135
October	1,202,545	504,495	164,647	3,699	371,543	147,509	10,651
November	1,273,766	704,389	130,744	3,150	305,513	122,409	7,561
December	1,400,059	784,395	149,838	4,806	329,283	125,894	5,843
Max NCP	1,685,647	908,055	209,299	6,485	403,648	147,509	10,651
% NCP Allocator (Gen)	100.00%	53.87%	12.42%	0.38%	23.95%	8.75%	0.63%

Rate Class Non-Coincident Monthly Peaks
At Sub-transmission Voltage Level

Date	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,356,033	822,095	171,296	6,485	308,607	41,583	5,968
February	1,416,932	876,096	164,220	5,806	287,191	77,178	6,442
March	1,345,783	770,928	148,919	5,058	348,368	64,883	7,628
April	1,280,493	697,785	140,164	3,811	356,731	72,283	9,718
May	1,268,175	610,606	163,500	3,715	403,648	77,310	9,395
June	1,565,384	876,028	193,323	3,537	400,141	82,363	9,991
July	1,535,923	864,726	204,352	4,347	380,577	72,571	9,351
August	1,596,874	908,055	206,900	4,374	386,409	83,106	8,030
September	1,329,473	703,151	177,090	4,038	362,163	74,896	8,135
October	1,141,067	504,495	162,583	3,699	371,543	88,095	10,651
November	1,223,092	704,389	129,000	3,150	305,513	73,479	7,561
December	1,345,588	784,395	147,455	4,806	329,283	73,806	5,843
Max NCP	1,623,834	908,055	206,900	6,485	403,648	88,095	10,651
% NCP Allocator (Sub)	100.00%	55.92%	12.74%	0.40%	24.86%	5.43%	0.66%

Rate Class Non-Coincident Monthly Peaks
At Primary Voltage Level

Date	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,305,717	822,095	170,430	6,485	298,720	2,020	5,968
February	1,333,644	876,096	163,276	5,806	277,798	4,226	6,442
March	1,271,367	770,928	147,419	5,058	337,156	3,179	7,628
April	1,198,273	697,785	138,372	3,811	344,895	3,691	9,718
May	1,173,278	610,606	161,925	3,715	383,761	3,876	9,395
June	1,472,458	876,028	192,532	3,537	387,504	2,866	9,991
July	1,453,488	864,726	203,570	4,347	368,765	2,729	9,351
August	1,504,787	908,055	206,289	4,374	374,754	3,284	8,030
September	1,245,270	703,151	176,555	4,038	350,345	3,046	8,135
October	1,042,791	504,495	162,007	3,699	359,080	2,858	10,651
November	1,140,585	704,389	128,479	3,150	294,762	2,244	7,561
December	1,262,117	784,395	146,956	4,806	317,991	2,126	5,843
Max NCP	1,523,210	908,055	206,289	6,485	387,504	4,226	10,651
% NCP Allocator (Pri)	100.00%	59.61%	13.54%	0.43%	25.44%	0.28%	0.70%

Rate Class Non-Coincident Monthly Peaks
At Secondary Voltage Level

Date	Total (kW)	R	C&G	CA-CSH	PH	PP	LIGHTING
January	1,236,874	822,095	168,356	5,846	234,609	-	5,968
February	1,267,461	876,096	161,448	5,247	218,228	-	6,442
March	1,193,209	770,928	145,382	4,486	264,785	-	7,628
April	1,116,463	697,785	136,328	3,287	269,344	-	9,718
May	1,088,524	610,606	159,329	3,119	306,074	-	9,395
June	1,389,633	876,028	189,847	2,859	310,908	-	9,991
July	1,375,533	864,726	201,135	3,666	296,655	-	9,351
August	1,423,114	908,055	203,807	3,680	299,543	-	8,030
September	1,171,234	703,151	174,212	3,400	282,336	-	8,135
October	964,187	504,495	159,399	3,074	286,568	-	10,651
November	1,075,347	704,389	126,377	2,665	234,355	-	7,561
December	1,188,779	784,395	144,554	4,266	249,722	-	5,843
Max NCP	1,439,267	908,055	203,807	5,846	310,908	-	10,651
% NCP Allocator (Sec)	100.00%	63.09%	14.16%	0.41%	21.60%	0.00%	0.74%

BEFORE
THE PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	)	
OF THE POTOMAC EDISON COMPANY	)	Case No. ____
FOR ADJUSTMENTS TO ITS RETAIL	)	
RATES FOR THE DISTRIBUTION OF	)	
ELECTRIC ENERGY	)	

DIRECT TESTIMONY OF
JOHN J. SPANOS

ON BEHALF OF
THE POTOMAC EDISON COMPANY

Concerning: Depreciation

March 22, 2023

DIRECT TESTIMONY OF
JOHN J. SPANOS

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Exhibits

DIRECT TESTIMONY OF
JOHN J. SPANOS

I. INTRODUCTION

Q. Please state your name and address.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. Are you associated with any firm?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since June 1986.

Q. What is your position with the firm?

A. I am President.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of The Potomac Edison Company ("Potomac Edison" or "the Company").

Q. Please state your qualifications.

A. I have over 36 years of depreciation experience, which includes expert testimony in over 420 cases before approximately 46 regulatory commissions in the United States and Canada. The cases include depreciation studies in the electric, gas, water, wastewater, and pipeline industries. In addition to the cases where I have submitted testimony, I have supervised over 800 other depreciation or valuation assignments. Please refer to Exhibit JJS-1A for additional information on my qualifications, which includes my leadership in the Society of Depreciation Professionals.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony will support and explain the Depreciation Study performed for Potomac Edison attached hereto as Exhibit JJS-2A ("Depreciation Study"). The Depreciation Study sets forth the calculated annual depreciation accrual rates by account as of June 30, 2022. My testimony presents depreciation concepts and an overview of the Depreciation Study. I also discuss the method of the recovery of net salvage (which is the net cost to remove or retire the Company's assets). I have discussed in detail in previous cases[1] problems with the design and implementation of the present value method for the recovery of net salvage that has been used in Maryland since 2007, referred to in my testimony as the "MD Present Value Method." It is my belief that the traditional straight line method for the recovery of net salvage would remedy the problems with the MD Present Value Method, would be most equitable to each generation of customers (otherwise referred to as "intergenerational equity"), and has not been accurately described in testimonies of other parties in previous cases. However, I also recognize that the Commission has adopted the MD Present Value Method in recent cases. In light of this precedent, the Company's proposal is to use the MD Present Value Method with a discount rate based on their credit-adjusted risk-free rate ("CARFR"). As both Staff[2] and I agree, recent Commission precedent supports the use of a CARFR[3] as the discount rate to be used to calculate the net salvage component of

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[1] See, for example Case No. 9490, Phase II for Potomac Edison and Case No. 9644 for Columbia Gas of Maryland.
[2] Direct Testimony of David Valcarenghi in Case No. 9680, p. 5.
[3] See Proposed Order from Case No. 9490, Phase II, p. 16, Point 45.

depreciation rates, rather than a discount rate based on a utility's rate of return. The Company's proposal using the CARFR results in an overall increase in depreciation expense of $2.5 million as of June 30, 2022.[4]

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR STUDY.

A. The results of the Depreciation Study are summarized by plant function in the table below, which sets forth the original cost and recommended annual depreciation rates and accruals based on electric plant in service as of June 30, 2022. A table summarizing the results by plant account using the traditional method can be found on page VI-4 of the study. Results using the MD Present Value Method with a 5.93% CARFR discount rate can be found in the Appendix of the study. The table below summarizes the results using both methods.

Table 1: Summary of Original Cost, Proposed Depreciation Rates and Amounts as of June 30, 2022
Based on Traditional and MD Present Value Methods

		TRADITIONAL METHOD		PRESENT VALUE METHOD	
FUNCTION	ORIG. COST, MILLIONS	DEPR. RATE	DEPR. AMOUNT, MILLIONS	DEPR. RATE	DEPR. AMOUNT, MILLIONS
ELECTRIC PLANT					
Intangible Plant	25.5	7.21	1.8	7.21	1.8
Distribution Plant	1,305.7	2.92	38.1	2.11	27.5
General Plant	67.5	3.80	2.6	3.70	2.5
Total Electric Plant	1,398.7	3.04	42.5	2.28	31.8

Q. ARE THE METHODS AND PROCEDURES OF THIS DEPRECIATION STUDY CONSISTENT WITH PAST PRACTICES?

[4] The Company's proposed depreciation adjustment of $3.0 million differs from the $2.5 million due primarily to differences between plant assets as of June 30, 2022 as compared to the 13-month average of plant assets during December 2021 through December 2022. Please refer to adjustment number 16 sponsored by Company witness Ward for additional details.

A. Yes. Most of the methods and procedures in this study are the same as those used in the previous Depreciation Study. Depreciation rates are determined based on the straight line method, the average service life procedure, and the remaining life technique. The study also provides the results using the MD Present Value Method with a discount rate based on the Company's CARFR. As will be discussed in more detail later in my testimony, these latter results are consistent with Commission precedent.

Q. ARE THE RECOMMENDED DEPRECIATION ACCRUAL RATES PRESENTED IN THE DEPRECIATION STUDY REASONABLE AND APPLICABLE TO THE PLANT IN SERVICE AS OF JUNE 30, 2022?

A. Yes, they are. Based on the Depreciation Study, I am recommending depreciation rates using the June 30, 2022 plant and reserve balances for approval. However, the Company has recently provided my firm with updated plant data as well as plant and reserve balances as of December 31, 2022 to synchronize with the end of the test year in the Company's distribution base rate case filing. Upon completion of updating my analysis with data as of December 31, 2022, I will update the Depreciation Study and the Company will file an update to its distribution base rate case to reflect the depreciation rate results of the updated Depreciation Study.

Q. HAVE YOU PREPARED A COMPARISON OF THE IMPACT OF THE NEW DEPRECIATION STUDY RESULTS TO THE CURRENT DEPRECIATION LEVELS?

A. Yes. Exhibit JJS-3A sets forth the currently approved depreciation rates and resultant depreciation expense to the proposed depreciation rates and expense as of June 30, 2022. The proposed depreciation rates set forth an increased annual depreciation expense of $2.5 million.

Q. **ARE POTOMAC EDISON'S PROPOSED DEPRECIATION RATES CONSISTENT WITH COMMISSION PRECEDENT AS IT APPLIES TO POTOMAC EDISON?**

A. Yes. Potomac Edison's proposed depreciation rates use the same methods for estimating service lives, net salvage and calculating depreciation for the original cost of plant that have been used in previous depreciation studies. For net salvage the proposed depreciation rates are based on the MD Present Value Method using a CARFR for the discount rate, which is consistent with more recent Commission precedent.[5]

Q. **HAS THE NET SALVAGE METHOD BEEN AN ISSUE IN PREVIOUS CASES BEFORE THE COMMISSION?**

A. Yes. Maryland has used the MD Present Value Method since 2007. However, other than the use of a modified version with an inflation-based discount in the District of Columbia, present value methods are not used for net salvage by any other U.S. regulatory jurisdiction. I have discussed in detail many reasons for concern that the continued use of the MD Present Value Method,[6] even with a more reasonable discount rate based on the CARFR, will result in an insufficient recovery of future net salvage, resulting in large regulatory asset balances and intergenerational inequity. While I still have these concerns, the depreciation rates proposed in this

[5] In Order No. 89971 in Case No. 9490, Phase II, the Commission explained that "The Commission explained that "[t]he PULJ found substantial evidence that the discount rate that should be used with the Present Value Method is a credit-adjusted risk-free rate, which 'takes into account inflation, but it is not the same as inflation.'" As discussed in more detail later in my testimony, Staff has agreed in at least two recent cases that using the CARFR is consistent with Commission guidance.

[6] See, for example, my Direct and Rebuttal testimonies in Case No. 9680.

proceeding, based on the MD Present Value Method, are reasonable in the context of Commission precedent.

Q. **BECAUSE THE COMPANY'S PROPOSED DEPRECIATION RATES USE THE MD PRESENT VALUE METHOD, WOULD YOU EXPECT DEPRECIATION TO BE A LESS CONTENTIOUS ISSUE THAN IN OTHER RECENT CASES?**

A. Yes. Not only is the Company's proposal consistent with Commission precedent, it also results in a small percentage increase in depreciation expense. That is, the depreciation rates proposed by the Company result in an increase in the Company's revenue requirement. Because the Company is ultimately proposing net salvage depreciation rates based on recent Commission precedent and the Company has not proposed a large increase in depreciation, I would expect depreciation to be a less contentious issue than it has been in previous cases. Had the Company solely proposed to use the traditional method, which is used in almost every state in the country, the increase to depreciation would have been larger than what the Company is proposing using the CARFR.

III. <u>DEPRECIATION CONCEPTS</u>

Q. **PLEASE DEFINE DEPRECIATION.**

A. The Federal Energy Regulatory Commission ("FERC") and the American Institute of Certified Public Accounts ("AICPA") provide two commonly used definitions for depreciation. FERC defines depreciation as follows:

> *Depreciation*, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not

> protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[7]

The AICPA defines depreciation as:

> Depreciation accounting is a system of accounting which aims to distribute cost or other basic value of tangible capital assets, less salvage (if any) over the estimate useful life of the unit (which may be a group of assets) in a systematic and rational manner. <u>It is a process of allocation, not of valuation</u>. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[8]

Q. **PLEASE DEFINE "SERVICE LIFE."**

A. The term service life refers to amount of time that an asset is providing utility service, or the period of time an asset is "in service." The term "useful life" is also used interchangeably with the term service life. FERC defines service life as follows:

> *Service life* means the time between the date electric plant is includible in electric plant in service, or electric plant leased to others, and the date of its retirement.[9]

Depreciation is a process of allocating the service value of an asset or group of assets over the service life or lives of the asset or assets.

Q. **WHAT IS "SERVICE VALUE"?**

A. Service value, as defined by FERC, is "the difference between original cost and net salvage value of electric plant."[10]

Q. **WHAT IS "NET SALVAGE"?**

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[7] 18 C.F.R. 101 (FERC Uniform System of Accounts), Definition 12.
[8] Accounting Research and Terminology Bulletin #1, AICPA, p. 25. (Emphasis added).
[9] FERC Uniform System of Accounts, Definition 36.
[10] FERC Uniform System of Accounts, definition 37.

A. Net salvage represents the cost to retire an asset, as well as any residual value of the asset, at the end of its service life. The FERC definition is that "*Net salvage value* means the salvage value of property retired less the cost of removal."[11] Net salvage is described as "positive net salvage" if the salvage value exceeds removal costs and described as "negative net salvage" (i.e., a net cost) if removal costs exceed the salvage value. It is common in utility operation for the cost of removal (also referred to as "cost of retirement") to exceed any salvage value at the end of an asset's life. Thus, net salvage is often a negative amount.

Q. WHY IS IT IMPORTANT TO INCLUDE NET SALVAGE IN DEPRECIATION RATES?

A. The net salvage related to an asset is a part of the service value of the asset. That is, any costs involved with retiring an asset (less any salvage), are part of the cost of providing electric or gas service to customers. For this reason, it is important that the net salvage costs are allocated to depreciation expense (and included in customer rates) while the asset is providing service. If the net salvage costs are instead recovered after an asset is retired, then future customers will have to pay these costs even though they received no benefit of the asset.

The National Association of Regulatory Utility Commissioners ("NARUC"), in its publication *Public Utility Depreciation Practices*, explains this concept:

> <u>The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, making due allowance for the net salvage, positive or negative, that will be obtained when the asset is retired</u>. This concept carries with it the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal. Hence, <u>if current users benefit from its use, they should pay their pro rata share of the costs involved in the</u>

[11] *Id.*, definition 19.

abandonment or removal of the property and also receive their pro rata share of the benefits of the proceeds realized.[12]

The concept that customers should pay their share of the costs of the assets that provide service to them is often referred to as "intergenerational equity." This concept is also similar to the accounting principle referred to as the "matching principle," under which costs of an asset are matched with the revenues generated during its service life. For depreciation accounting, intergenerational equity is typically understood to mean that depreciation rates are designed to allocate an equal amount of the asset's service value to each year of service.[13]

Q. HOW IS DEPRECIATION DETERMINED?

A. The first step in the depreciation process is to estimate the service lives and net salvage for each group of assets being studied. I will describe this process of estimation in the next section and the process is also described in more detail in the Depreciation Study. Once service lives and net salvage estimates have been determined, a depreciation system needs to be established in order to calculate depreciation.

Q. **WHAT IS A "DEPRECIATION SYSTEM"?**

A. The term "depreciation system" refers to the methods, procedures and techniques used to calculate depreciation expense. To calculate depreciation, one must determine the appropriate depreciation concept, depreciation method, calculation or grouping procedure, and technique to be used.

Q. **PLEASE EXPLAIN WHAT YOU MEAN BY A "CONCEPT."**

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[12] National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices*, 1996, p. 18. (Emphasis added).
[13] This understanding is set forth in the NARUC passage cited above with the use of the term "pro rata share."

A. The term "concept" refers to the accounting concept (or concepts) by which depreciation is determined. As noted in the definitions provided above, depreciation for accounting and ratemaking is typically based on a cost allocation concept. Capital costs that have been or will be expended (i.e., the service value of an asset) are allocated to the accounting periods in which an asset is in service (i.e., its service life). A cost allocation concept contrasts with a value or valuation concept, in which depreciation is determined based on estimates of the value of an asset and the change in value over time.

Q. **WHAT IS A "DEPRECIATION METHOD?"**

A. The term "depreciation method" refers to the method by which costs are allocated to each period for which an asset renders service. There are three general categories of depreciation methods: straight line, deferred (also referred to as "decelerated") and accelerated. For the straight line method, costs are allocated ratably, or in an equal amount, to each period that the asset is in service. For a deferred method, fewer costs are allocated to earlier periods and more to later periods. For an accelerated method, more is allocated to early periods than to later periods.

Similar to the cost allocation concept, the straight line method is used almost universally for accounting and ratemaking and is supported by depreciation textbooks and precedent in most regulatory jurisdictions. However, Maryland has used different methods for different aspects of depreciation. The straight line method is used for the original cost of a company's assets but the Present Value Method, which is a deferred method, has been used for future net salvage.

Q. **WHAT IS A "PROCEDURE"?**

A. A depreciation procedure, or “grouping procedure,” describes the manner in which a group of assets is organized to calculate depreciation. Utilities typically have a large number of assets, and therefore group similar assets into property groups (as opposed to depreciating each unit individually). There are different procedures that can be used to calculate depreciation for a group of property. Under the average service life (or “broad group” or “average life group”) procedure, a group of similar assets, such as poles, is organized as a single group and depreciated over the average service life or average remaining life of the group. Under the “vintage group” procedure, depreciation is calculated separately for each vintage[14] of assets within a group. Under the “equal life group” (or “unit summation”) procedure a group of assets is subdivided based on the estimated survivor curve[15] into groups that have the same service life. Depreciation is then calculated separately for each of these “equal life groups.”

Each of these procedures is recognized and accepted in regulatory jurisdictions in the U.S. However, the average service life procedure is the most common.

Q. **WHAT IS A “TECHNIQUE?”**

A. The term “technique” refers to the manner by which depreciation is calculated to ensure that the full service value of an asset is recovered through depreciation expense. Under the “whole life technique,” depreciation expense is simply

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[14] The “vintage” for an asset refers to the year in which the asset was placed into service. The term “installation year” is also used.

[15] A survivor curve is a mathematical description of the percentage of plant installed that is expected to survive, or remain in service, to a given age. A survivor begins at 100 percent surviving at age zero and declines to zero percent surviving over time.

calculated based on the "whole life" of an asset or group of assets. That is, an asset with a 10-year life and no net salvage would have a 10% (or 1/10) depreciation rate.

In contrast, remaining life technique allocates the remaining undepreciated service value of an asset or group of assets over the estimated remaining life of the asset or group of assets. The remaining life technique therefore incorporates a self-correcting mechanism that will adjust depreciation expense for any over- or under-recoveries that have occurred in the past. The remaining life technique ensures that the full service value of the Company's assets are recovered through depreciation expense – no more, no less.

For this reason, the remaining life technique is the most common technique used for utility depreciation. There are certain jurisdictions that use whole life depreciation, but these jurisdictions will often use an explicit adjustment to depreciation in an effort to ensure that the correct amount of costs is recovered through depreciation expense.

Q. HOW DOES THE DEPRECIATION SYSTEM IMPACT DEPRECIATION EXPENSE?

A. Depending on the concept, method, procedure, and technique used, different amounts of annual depreciation expense will be calculated, even if the service life and net salvage estimates remain the same. The depreciation system used also has an impact on intergenerational equity, as different depreciation systems will allocate different amounts to different generations of customers. If too little is allocated to today's customers (as is the case with the MD Present Value Method), future customers will have to pay more than their fair share. Similarly, if too much expense is allocated to today's customers, future generations will pay less than their fair share. Depreciation expense (and therefore the depreciation system selected) also has an impact on rate base because accumulated depreciation is a deduction from rate base. Therefore, if too little depreciation is allocated to today's customers, future customers will pay more depreciation expense in the future and will also pay a higher return on rate base.

IV. DEPRECIATION STUDY

Q. DID YOU PREPARE THE DEPRECIATION STUDY FILED BY POTOMAC EDISON IN THIS PROCEEDING?

A. Yes. I prepared the Depreciation Study, and Exhibit JJS-2A is a true and accurate copy of my report. My report is entitled: "2022 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of June 30, 2022." This report sets forth the results of my Depreciation Study for Potomac Edison.

Q. IN PREPARING THE DEPRECIATION STUDY, DID YOU FOLLOW GENERALLY ACCEPTED PRACTICES IN THE FIELD OF DEPRECIATION VALUATION?

A. Yes.

Q. WHAT IS THE PURPOSE OF THE DEPRECIATION STUDY?

A. The purpose of my Depreciation Study was to estimate the annual depreciation accruals for Potomac Edison's plant in service for financial and ratemaking purposes, and to determine appropriate average service lives and net salvage percentages for each plant account.

Q. ARE THE METHODS AND PROCEDURES OF THIS DEPRECIATION STUDY CONSISTENT WITH POTOMAC EDISON'S PAST PRACTICES?

A. Yes. The depreciation methods and procedures of this study are determined based on the average service life procedure and the remaining life method. However, the methodology of net salvage has a different discount rate utilized since the last study.

For general plant assets, amortization periods were established based on the nature of the assets in each account.

Q. PLEASE DESCRIBE THE CONTENTS OF THE DEPRECIATION STUDY.

A. The Depreciation Study is presented in nine parts. Part I, Introduction, presents the scope and basis for the Depreciation Study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curves. Parts III and IV set forth the analysis for determining service life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life. Part VI, Results of Study, presents a description of the results of my analysis and a summary of the depreciation calculations. Part VI also includes Table 1 (see page VI-4), which presents the estimated survivor curve, the net salvage percent, the original cost as of June 30, 2022, the book depreciation reserve, and the calculated annual depreciation accrual and rate for each account or subaccount. Parts VII, VIII and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations by account. The section beginning on page VIII-2 presents the results of the salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of June 30, 2022. The Appendix to the study provides the study results using the MD Present Value Method with a CARFR of 5.93%.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION

STUDY.

A. I used the straight line remaining life method of depreciation, with the average service life procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and reasonable manner.

For General Plant Accounts 391.0, 391.15, 391.2, 393.0, 394.0, 395.0, 397.0 and 398.0, I used the straight line remaining life method of amortization.[16] The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage study consisted of compiling historical data from

[16] The account numbers identified throughout my testimony represent those in effect as of June 30, 2022.

records related to Potomac Edison's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from Potomac Edison's management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the data and the estimates used by other electric utilities to form judgments of average service life and net salvage characteristics.

Q. WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Company's accounting entries that record plant transactions during the period 1997 through June 2022 to the extent available. The transactions I analyzed included additions, retirements, transfers, sales, and the related balances.

Q. WHAT METHOD DID YOU USE TO ANALYZE THESE SERVICE LIFE DATA?

A. I used the retirement rate method for most plant accounts. This is the most appropriate method when retirement data covering a long period of time is available because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the Depreciation Study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE POTOMAC EDISON'S SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group.

Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The "Iowa-type survivor curves" were used to perform these interpretations.

Q. **WHAT ARE "IOWA-TYPE SURVIVOR CURVES" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?**

A. Iowa-type survivor curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. These curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa-type survivor curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves were used in the Depreciation Study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements. The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 50-R1.5 indicates an average service life of 50 years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a low height, 1.5, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. **HAVE POTOMAC EDISON'S PLANT AND EQUIPMENT BEEN PHYSICALLY OBSERVED AS PART OF YOUR DEPRECIATION STUDY?**

A. Yes. A field review of Potomac Edison's property was conducted on February 6, 2023 to observe representative portions of plant. Field reviews in 2020 had also been reviewed for Potomac Edison as well as visits of the similar assets of other FirstEnergy properties. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with Potomac Edison's management and operating personnel, was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. **HOW DID YOUR EXPERIENCE IN DEVELOPMENT OF OTHER DEPRECIATION STUDIES AFFECT YOUR WORK IN THIS CASE FOR POTOMAC EDISON?**

A. Because I customarily conduct field reviews for my depreciation studies, I have had the opportunity to visit scores of similar facilities and meet with management and operations personnel at many other companies other than Potomac Edison. The knowledge I have accumulated from those visits and meetings provides me with useful information to draw upon to confirm or challenge my numerical analyses concerning asset condition and remaining life estimates.

Q. **PLEASE EXPLAIN THE CONCEPT OF "NET SALVAGE".**

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire the asset exceeds the salvage value, the result is negative net salvage.

Because depreciation expense is the loss in service value of an asset during a defined period (*e.g.*, one year), it must include a ratable portion of both the original cost of the asset and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost, so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value. For example, the full service value of a $500 line transformer also includes $200 of cost of removal and $25 gross salvage, for a total service value of $675.

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. Using the widely accepted traditional method, I estimated the net salvage percentages by incorporating the Company's actual historical data for the period, 2001 through June 2022, and considered industry experience of net salvage estimates for other electric companies. The net salvage percentages in the Depreciation Study are based on a combination of statistical analyses and informed judgment. The statistical analyses consider the cost of removal and gross salvage ratios to the associated retirements during the 22-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group using the straight line remaining life method, and using remaining lives weighted consistent with the average service life procedure. The calculation of annual depreciation accrual rates was developed for electric plant in service as of June 30, 2022.

Q. PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE METHOD OF DEPRECIATION.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life. The use of the remaining life technique incorporates a self-correcting mechanism that will adjust depreciation expense for any over-or under-recoveries that have occurred in the past. The remaining life technique, therefore, ensures that the entire service value of the Company's assets is recovered through depreciation expense. The entire service value of the Company's assets is the original cost less net salvage. I also calculated depreciation rates based on the MD Present Value Method, which are provided in Appendix A of the Depreciation Study.

Q. PLEASE DESCRIBE THE AVERAGE SERVICE LIFE PROCEDURE FOR CALCULATING REMAINING LIFE ACCRUAL RATES.

A. The average service life procedure defines the group or account for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life and the rate is then applied to the surviving balance of the group's cost. The average remaining life of the group is calculated by first dividing the future book accruals (original cost less allocated book reserve less future net salvage) by the average remaining life for each vintage. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. The sum of the future book accruals is then divided by the sum of the annual accruals to determine the average remaining life of the entire group for use in calculating the annual depreciation accrual rate.

Q. PLEASE DESCRIBE AMORTIZATION ACCOUNTING IN CONTRAST TO DEPRECIATION ACCOUNTING.

A. Amortization accounting is used for accounts with a large number of units, but small asset values. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, depreciation accounting is difficult for these types of assets because depreciation accounting requires periodic inventories to properly reflect plant in service. Consequently, amortization accounting is used for these types of assets, such that retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement in amortization accounting. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period that represents an anticipated life during which the asset will render full benefit. For example, in amortization accounting, assets that have a 20-year amortization period will be fully recovered after 20 years of service and taken off the Company's books at that time, but not necessarily removed from service. In contrast, assets that are taken out of service before 20 years remain on the books until the amortization period for that vintage has expired.

Q. IS AMORTIZATION ACCOUNTING BEING UTILIZED FOR CERTAIN PLANT ACCOUNTS?

A. Yes. However, amortization accounting is only appropriate for certain General Plant accounts. These accounts are 391.0, 391.15, 391.2, 393.0, 394.0, 395.0, 397.0 and 398.0, which represent slightly more than two percent of Potomac Edison's depreciable plant.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE HOW THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IS PRESENTED IN YOUR DEPRECIATION STUDY.

A. I will use Account 367.0, Underground Conductors and Devices, as an example because it is the largest depreciable account and represents approximately 21 percent of depreciable plant. The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1997 through June 2022 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1997-2022 and 2013-2022 experience bands are presented on pages VII-27 through VII-31 of the Depreciation Study. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page

VII-28 of the study shows $1,939,728 retired at age 0.5 with $252,365,753 exposed to retirement. Consequently, the retirement ratio is 0.0077 and the surviving ratio is 0.9923. The life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 44-R3 on page VII-27 of the study.

The net salvage analysis for Account 367.0 is presented on pages VIII-12 and VIII-13 of the Depreciation Study. The percentages are based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 2001 through 2022. This 22-year period experienced $15,757,576 ($28,388 - $15,785,964) in net salvage for $29,239,056 plant retired. The result is negative net salvage of 54 percent ($15,757,576/$29,239,056). Based on the overall negative 54 percent net salvage and the most recent five years of negative 66 percent, as well as industry ranges and Company expectations, it was determined that negative 50 percent is the most appropriate estimate.

My calculation of the annual depreciation related to the original cost of the account as of June 30, 2022 is presented on pages IX-17 and IX-18 of the study. The calculation is based on the 44-R3 survivor curve, 50 percent negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life, and annual accrual. These totals are brought forward to the table on page VI-4 of the Depreciation Study.

Q. DID YOU DEVELOP RATES FOR NEW AND FUTURE ASSETS THAT MAY BE PLACED IN SERVICE?

A. Yes. There are two new plant accounts that the Company has added and expects to add to plant in service in the near future. One of the accounts is Account 363.00 Electric Storage Battery which should be depreciated based on a 15-year life and zero percent net salvage. The depreciation rate for this account will be 6.67%. The other new plant account is Account 371.10 Electric Vehicle Charging Stations which should be depreciated based on a 10-year life and a zero percent net salvage. The depreciation rate for this account will be 10.00%. These depreciation rates are set forth in the Depreciation Study on page VI-4.

V. NET SALVAGE METHODOLOGY

Q. IN SECTION III, YOU EXPLAINED THE CONCEPT OF NET SALVAGE. DO THE COSTS INCLUDED IN DEPRECIATION EXPENSE NORMALLY INCLUDE AN ESTIMATE OF NET SALVAGE?

A. Yes, they do. As required by the FERC Uniform System of Accounts ("USofA") and explained in authoritative depreciation texts, the service value of an asset includes the net salvage costs at the end of the asset's life. For this reason, depreciation must include an estimate of net salvage in order to allocate these costs over the lives of the assets.

Q. HOW IS NET SALVAGE NORMALLY INCLUDED IN DEPRECIATION EXPENSE?

A. By far, the most common approach is to use what has often been referred to as the "traditional method." This method is called the "traditional method" in part because it is so widely used in the industry for the recovery of net salvage. In the traditional method, an estimate of future net salvage costs is made based on informed judgment that incorporates a statistical analysis of historical net salvage data in which net salvage is expressed as a percentage of retirements. The estimated net salvage is then allocated on a straight line basis over the service lives of the Company's assets. This approach is consistent with the concept of depreciation as a method of cost allocation. The traditional method is also widely accepted by almost all jurisdictions and by authoritative depreciation texts.

Q. IS THIS METHOD CURRENTLY IN USE IN MARYLAND?

A. No. Maryland currently uses the MD Present Value Method, which is a method that is unique to Maryland. When using this method, net salvage has been estimated in a similar manner to the traditional method. However, the MD Present Value Method does not allocate these costs on a straight line basis but instead uses a deferred method of recovery based on a discount rate. The deferred method of recovery is used only for net salvage, while the straight line method is used for the original cost of the Company's assets.

Q. HOW DOES THE MD PRESENT VALUE METHOD WORK?

A. Unlike in most jurisdictions, in which net salvage is recovered in equal amounts over the life of property using the straight line method, the MD Present Value method discounts future net salvage cost to an estimated present value. This present value is then recovered through current depreciation rates. As the present value increases over the life of the property, customers pay interest at a rate equal to the discount rate used in the calculations, and the annual amount of net salvage recovered increases over the life of the property.[17] Because utility property service lives typically span decades, the discount rate used for the MD Present Value

[17] Customers also pay a higher revenue return on rate base because the low historical recovery of the present value of net salvage costs results in a higher rate base on which customers pay a return.

Method calculations has a significant impact on the resultant annual net salvage accruals.

Q. WHAT DISCOUNT RATE HAS BEEN USED IN PRIOR CASES IN MARYLAND FOR THE MD PRESENT VALUE METHOD?

A. The MD Present Value method was first adopted in 2007 in Case No. 9092 for the Potomac Electric Power Company ("Pepco"). In that case, the Staff of the Maryland Public Service Commission ("Staff") hired an external consultant, William Dunkel, who provided testimony discussing methods for recovering net salvage through depreciation and recommended the use of the MD Present Value Method. The MD Present Value Method had not, to my knowledge, been previously used in any other regulatory jurisdiction.[18] Mr. Dunkel's rebuttal testimony (Mr. Dunkel did not provide direct testimony in that case) assessed three methods that had been proposed by either the Company or by Maryland Office of People's Counsel ("OPC") – the traditional straight line method, a Historical Recovery method,[19] and the MD Present Value Method. The only depreciation proposal using the MD Present Value Method in Case No. 9092 incorporated Pepco's overall rate of return as the discount rate. The Commission adopted the MD Present Value Method in that case, establishing a precedent for both the method and the use of the rate of return as the discount rate.

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[18] Subsequent to Case No. 9092, the District of Columbia ("DC") Public Service Commission adopted a Present Value method with similar formulas to the MD Present Value Method. However, inflation-based discount rates were used in DC rather than the overall cost of capital or a CARFR.

[19] The term "historical recovery" method was used by the Commission in Case No. 9092. This method may also be referred to as the net salvage expense method, the net salvage normalization method, the five-year average net salvage method or the Pennsylvania method.

Q. WAS THE IMPACT OF THE DISCOUNT RATE GIVEN FULL CONSIDERATION IN CASE NO. 9092?

A. No. The focus of testimony in that case was on the method, rather than specifics such as the discount rate. Indeed, the Commission concluded that the MD Present Value Method was a middle ground between the traditional method and the Historical Recovery method, stating:

> The Present Value Method strikes a balance between the straight line and historical recovery proposals. It is a forward looking approach like the Straight Line Method and recovers projected costs over the life of the plant. However, because future costs are discounted to a “present value,” today's ratepayers will pay only their fair share of recovery costs in “real” dollars rather than the inflated amounts under the Straight Line Method. In our opinion, the Present Value Method strikes an appropriate balance between the interests of current and future ratepayers.”[20]

As my associate Ned W. Allis recently discussed in detail in Case No. 9670,[21] Case No. 9092 was, to my knowledge, the first time the MD Present Value Method was adopted in the utility industry in any jurisdiction. The experience in Maryland since Case No. 9092 concluded in 2007 is, therefore, the only experience in the industry of using this method. Based on the experience of Maryland utilities, the MD Present Value Method has not struck a balance between the traditional and Historical Recovery methods, as, for each of the electric utilities in the state, it has recovered less in net salvage through depreciation than has been incurred and has not resulted in customers paying their fair share of net salvage costs in “real” (i.e., inflation-adjusted) dollars. There are several reasons the MD Present Value

[20] Order No. 81517 in Case No. 9092, p. 31.
[21] See the Rebuttal Testimony of Ned W. Allis in Case No. 9670 beginning on page 44 for a discussion of the history of the MD Present Value Method in Maryland.

Method has not worked as the Commission intended, one of which is the use of the overall rate of return as the discount rate.

Q. HAVE ANY CHANGES BEEN MADE TO MD PRESENT VALUE METHOD SINCE IT WAS INITIALLY ADOPTED IN CASE NO. 9092?

A. Yes. The Commission has approved several changes to the MD Present Value Method since Case No. 9092. These include modifications in Case Nos. 9103,[22] 9096,[23] 9610[24] and 9670.[25] The fact that the MD Present Value Method has repeatedly been modified since its adoption provides further evidence that an additional refinement to change the discount rate would be reasonable if the Method is going to continue to be used.

Q. HAVE THE COMMISSION OR OTHER PARTIES SUGGESTED THAT A CHANGE TO THE DISCOUNT RATE FOR THE MD PRESENT VALUE METHOD COULD BE APPROPRIATE?

A. Yes. While for several years the Commission, Staff and OPC continued to support the rate of return as the discount rate, in more recent cases parties, including the Commission, appear to have begun to recognize that the rate of return is too high of a discount rate and that an alternative would be more appropriate. Statements of this conclusion include:

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[22] A change to perform calculations by vintage was proposed by Staff and adopted on pages 15 and 16 of the Proposed Order in Case No. 9103.

[23] See the discussion on pages 28 and 29 of the Surrebuttal Testimony of William Dunkel in Case No. 9096 as well as Order No. 83310.

[24] In Case No. 9610, OPC witness William Dunkel proposed to use significantly more negative net salvage estimates to address issues with the MD Present Value Method results. See pages 77 to 81 of my rebuttal testimony in Case No. 9610 for a further discussion of this proposal, which resulted in depreciation rates that were similar to those resulting from the traditional method. Mr. Dunkel's modifications to the MD Present Value Method were included in the settlement agreement in Case No. 9610 that was approved by the Commission.

[25] In the settlement in Case No. 9670, the parties agreed to allow the amortization of the negative reserve for net salvage. The settlement agreement was approved in Order No. 90098 on pages 13 and 14.

- In Case No. 9609, the Public Utilities Law Judge ("PULJ"), in reviewing the record in that case, found several issues with the MD Present Value Method. These included that the use of the rate of return as the discount rate meant that "customers toward the end of an asset's life will pay much more for the removal of the asset than customers early in the asset's life (in dollars that reflect the time value of money or 'real dollars')," which the PULJ found to be "troubling." The PULJ also found that the record was "replete with evidence that the [MD Present Value Method] has an upward impact on a utility's rate of return revenue due to the upward impact on a utility's net plant" and that "rates will be higher over the long term than if the traditional straight line method is used." While the PULJ suggested that the Commission might find that the benefits of the MD Present Value Method do not outweigh the costs and might consider "reverting to the use of the traditional straight line method," the PULJ opted to continue to use the MD Present Value Method but with a more reasonable 2.5% inflation-based discount rate rather than the rate of return as the discount rate.[26] The Commission eventually declined to use this refinement because it believed the record did not support the 2.5% discount rate.[27]
- In the settlement in Case No. 9644 for Columbia Gas of Maryland ("Columbia"), the parties agreed that "In its next base rate case, the Company agrees to use a discount factor in the development of a net salvage

[26] See pp.32 to 35 of the Proposed Order in Case No. 9609.
[27] See Order No. 89403 in Case No. 9609, pp. 11 and 12.

component that is consistent with the Company's credit-adjusted risk-free rate."[28]

- In Columbia's next case, Case No. 9664, the PULJ found that "[t]here is evidence that a credit-adjusted risk-free rate is appropriate to use as the discount rate in the SFAS 143 methodology,[29] but there is insufficient evidence in the record to support what that rate should be for Columbia. Without further expert testimony, there is no way to compare which discount rate, a credit-adjusted risk-free rate or the ROR, would be more appropriate. Columbia has failed to meet its burden of proof on the issue by using a discount factor based solely on inflation. Therefore, consistent with Commission decisions, I accept the positions of Staff and OPC, that the Company's authorized ROR will be used as the discount rate."[30] This finding was not appealed to the Commission.
- In Phase II of Case No. 9490 for Potomac Edison, the Commission also appeared to find that, while the record in that case did not support a specific credit-adjusted risk-free rate, the use of a credit-adjusted risk-free rate would be appropriate. The Commission explained that "[t]he PULJ found substantial evidence that the discount rate that should be used with the Present Value Method is a credit-adjusted risk-free rate, which 'takes into account inflation, but it is not the same as inflation.'"[31] The Commission

[28] See paragraph 1.g of the settlement agreement in Case No. 9644.
[29] SFAS 143 is an acronym for Statement of Financial Accounting Standard No. 143 and is the purported basis for the establishment of the MD Present Value Method (although the MD Present Value Method is inconsistent with both the intended use and the proper operation of SFAS 143).
[30] See Proposed Order in Case No. 9664, p. 18.
[31] See Order No. 89971 in Case No. 9490, p. 4.

also stated that "[d]eveloping a credit-adjusted risk-free rate requires analyzing market data such as the interest rate environment and the general state of the economy, as well as a company's financial condition, including financing arrangements. As the PULJ observed, however, no such analysis was performed in this case."[32]

- In Case No. 9670 for Delmarva Power & Light Company ("DPL"), in response to several issues identified with the MD Present Value Method, Staff supported the use of DPL's credit-adjusted risk-free rate as an alternative to the rate of return. Mr. Valcarenghi testified that "[i]n this alternative I utilized the present value method for recovering net salvage costs, just as I did in my direct testimony, except I have utilized a lower discount factor of 3.04%. This alternative discounts the net salvage costs based on the use of a credit-adjusted risk free rate, rather than by using the rate of return."
- In Case No. 9680 for Columbia Gas of Maryland, Columbia's proposal was based on the MD Present Value Method using the CARFR as the discount rate. Staff supported the use of the CARFR as the discount rate, testifying that "[g]iven recent guidance from the Commission, Staff believes it is appropriate to recommend a discount rate developed on a basis other than rate of return. Staff believes a discount rate based on a credit-adjusted risk-free rate ("CAFR") is a preferred rate because provides a more stable pathway for recovery of costs."[33] Staff's proposal supported a different

[32] See Order No. 89971 in Case No. 9490, p. 20.
[33] See Direct Testimony of David Valcarenghi in Case No. 9680, p. 5, lines 10-14.

CARFR than Columbia's proposal, however, as will be discussed in more detail later in this testimony.

- MD and DC OPC have hired several consulting firms in the past five years in the only two jurisdictions using any version of the Present Value Method. In recognition of issues with the MD Present Value Method, each firm has proposed or recognized alternatives to the approach:
  - In BGE's most recent case, Case No. 9610, OPC witness William Dunkel proposed to use significantly more negative net salvage estimates than those used in the traditional method. His proposal resulted in recovery of net salvage that was similar to the recovery resulting from the traditional method.[34]
  - In Case No. 9609, OPC witness David Garrett suggested a different rate might be appropriate. As described by the PULJ, "OPC Witness Garrett testified that a negative impact of the [MD Present Value] Method might not indicate a problem with the [MD Present Value] Method itself, but with the discount rate being used. He suggested that the methodology might need to be modified. OPC and Staff used rate of return as the discount factor because that is what has been accepted in the past. However, as Witness Garrett testified, there is not just one way to apply a

[34] See pp. 77 to 81 of my rebuttal testimony in Case No. 9610 for a further discussion of this proposal, which resulted in depreciation rates that were similar to those resulting from the traditional method.

present value methodology and there is no requirement that the discount rate be equal to the rate of return."[35]

- OPC has hired the consulting firm Snavely King in several recent cases. When testifying in the District of Columbia, Snavely King[36] testified that the discount rate for the Present Value Method should be the rate of inflation. The Snavely King witness explained that "[t]he primary objective of the present value method is to match charges for future inflation to future periods instead of the current period. The 7.96% discount rate reflects the 'current approved cost of capital for PEPCO in the District of Columbia jurisdiction…' Use of a rate of return as the discount rate implies that such rate bears some relationship to earnings. However, the purpose of using a discount rate in this context is simply to remove the effects of future inflation from PEPCO's charges to current customers."[37]

In the overall context of these testimonies and Orders, there appears to be at least some measure of consensus that an alternative to the use of a utility's rate of return would be reasonable for the discount rate for the MD Present Value Method. Additionally, both the Commission and Staff have acknowledged that the use of a CARFR interest rate may be appropriate.

[35] See Proposed Order in Case No. 9609, pp. 32-33.
[36] The Snavely King witness in the District of Columbia case was a different witness from James Garren, who also worked for Snavely King and has testified on behalf of OPC in recent Maryland cases.
[37] See Direct Testimony of Michael Majoros, District of Columbia Public Service Commission Case No. 1076, p. 20.

Q. DOES SFAS 143 SUPPORT THE USE OF THE RATE OF RETURN AS THE DISCOUNT RATE?

A. No. To the contrary, paragraph 8 of SFAS 143 makes clear that a CARFR must be used when accounting for asset retirement obligations ("AROs")[38] :

> An expected present value technique will usually be the only appropriate technique with which to estimate the fair value of a liability for an asset retirement obligation. An entity, when using that technique, shall discount the expected cash flows using a credit-adjusted risk-free rate. Thus, the effect of an entity's credit standing is reflected in the discount rate rather than in the expected cash flows.

I will note that I have reviewed the depreciation-related testimonies and Order in Case No. 9092, in which the MD Present Value Method was initially adopted. I have not found any testimony as to why, for a method allegedly based on SFAS 143, both OPC and Staff consultants used a much higher discount rate than required by SFAS 143. Neither party provided testimony in Case No. 9092 explaining this deviation from SFAS 143. It is unclear whether this was inadvertent – perhaps the witnesses supporting this method did not fully understand the implications of the discount rate – or whether it was intended as a way to further reduce depreciation. I also find it puzzling because I have seen both of these consulting firms propose the use of different discount rates elsewhere – Staff's consultant from Case No. 9092 has used a CARFR – that is, a lower rate than the rate of return - when proposing a present value method elsewhere[39] and, as noted

[38] I note here that SFAS 143 is not intended to recover net salvage costs through depreciation but is instead a method to recognize liabilities for AROs on the balance sheet. However, because the MD Present Value Method is purportedly based on SFAS 143, the guidance of this accounting standard has relevance to the application of the MD Present Value Method.

[39] For example, in Utah Case No. 13-035-02, Mr. Dunkel used a 5.50% discount rate that was consistent with the CARFR for Rocky Mountain Power, rather than a higher discount rate based on the overall rate of return. Mr. Dunkel's proposal was not adopted in that case.

above, OPC's consultant in Case No. 9092 supported an inflation-based discount rate in the District of Columbia.

With all of this in mind, there really is not a conceptual justification for using the rate of return as the discount rate, particularly because the use of a high discount rate has contributed to a myriad of problems resulting from the use of the MD Present Value Method since Case No. 9092.[40] If the Commission intends for the MD Present Value Method to be more consistent with the accounting pronouncement on which the method is apparently based, then the use of a CARFR would be more appropriate.

Q. HOW IS A CARFR RATE DETERMINED?

A. SFAS 143 defines the CARFR as "an interest rate that equates to a risk-free interest rate adjusted for the effect of its credit standing (a credit-adjusted risk-free rate)."[41] This definition sets forth two components in determining a CARFR. The first is determining the risk-free rate. The risk-free rate is typically considered to be the interest rate for U.S. Treasury bonds, since it is assumed the default risk for U.S. government bonds is minimal. The second is determining an adjustment for the effect of a company's credit standing. There is a third component as well, which is the duration to which the interest rate applies (i.e., five-year, ten-year, thirty-year, etc.). Thus, the CARFR is effectively the interest rate for a company's debt for a given time and duration.

[40] For a more complete discussion of the issues that have arisen due to the MD Present Value Method, see the rebuttal testimony of Ned W. Allis in Case No. 9670.
[41] See SFAS 143, paragraph A21.

Q. HAS THE COMMISSION PROVIDED ANY INDICATION OF HOW A CARFR RATE SHOULD BE DETERMINED?

A. Yes. In Phase II of Case No. 9490, the Commission stated "[d]eveloping a credit-adjusted risk-free rate requires analyzing market data such as the interest rate environment and the general state of the economy, as well as a company's financial condition, including financing arrangements."[42]

Q. HAVE ANY OTHER PARTIES SUPPORTED A CARFR IN PREVIOUS PROCEEDINGS AND, IF SO, HOW WAS THE CARFR DETERMINED?

A. Yes. As discussed above, in Case No. 9670, Staff supported an alternative proposal which used a CARFR as the discount rate. For Case No. 9670, the 3.04% rate Staff witness Valcarenghi supported was based on the most recently available interest rates at the time, which were determined as of June 30, 2021. The 3.04% rate was determined for a 30-year duration and based on a 2.09% treasury rate and a 0.95% adjustment for DPL's credit standing. Both of these were generally in line with 30-year treasuries and the spreads between these rates and the interest rates of the same duration that were consistent with the company's credit rating as of June 30, 2021. A 30-year duration was used because the service lives of most electric distribution plant assets have service lives of 30 years or more.

In case No. 9680, Columbia proposed to use a discount rate based on the CARFR. My firm provided testimony in support of the discount rate proposed in that case, which included analyses of 30-year U.S. treasury yields, utility bond yields of the same duration, and the spreads between these two yields. Staff's

[42] See Order No. 89971 in Case No. 9490, p. 20.

witness also supported the use of the CARFR in that case.[43] While Staff's proposed discount rate differed from Columbia's proposal, Staff's analysis supporting their proposal was fundamentally similar to my firm's and the differences were due more to the time periods analyzed and data incorporated in the analysis, rather than with the general approach of considering the three variables discussed above.

Q. WHAT IS YOUR RECOMMENDATION FOR THE CARFR?

A. The recommendation for this proceeding is to use a CARFR rate consistent with the Company's discount rate utilized for the recent utility bond yield of 5.93% for the most recent period available at the time the study was completed, which was the three months ending December 31, 2022. This discount rate was based on the average of the yield on Potomac utility bonds for the final three months of 2022. This is slightly higher than the range of the 30-year treasury bond through the end of 2022.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE NET SALVAGE METHOD IN THIS PROCEEDING?

A. While I continue to believe the traditional method is most appropriate, the Company's proposal in this case is to use depreciation rates based on the estimates in the Depreciation Study calculated with the MD Present Value Method and a discount rate based on the CARFR, consistent with recent MD Commission precedent. These depreciation rates are set forth in the appendix to the Depreciation Study.

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[43] See Direct Testimony of David Valcarenghi in Case No. 9680, p. 5.

VI. CONCLUSION

Q. WAS THE DEPRECIATION STUDY FILED BY POTOMAC EDISON IN THIS PROCEEDING PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Exhibit JJS-1A

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy

Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee- American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Energy Arkansas, Inc.; Black Hills Kansas

Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire and Newtown Artesian Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service

Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-ICC-06	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-ICC-06	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.	G-5, Sub522	Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	Docket No. 2011-UA-183	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	RP11-___-000	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14- -0000	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Corporation	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC	Cause No. 45029	Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217-000	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211-000	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-190529 / UG-190530	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-3010955	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326.	2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327.	2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Progress	Depreciation
329.	2019	MD PSC	Case No. 9609	NiSource Columbia Gas of Maryland, Inc.	Depreciation
330.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
331.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
334.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
335.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation
336.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
337.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
338.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
339.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
340.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	Depreciation
341.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
342.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
343.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
344.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
345.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
346.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
347.	2020	OR PSC	UE 374	PacifiCorp	Depreciation
348.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
349.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
350.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of	Depreciation
351.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
352.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
353.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
354.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
355.	2020	OR PSC	UG 388	Northwest Natural Gas Company	Depreciation
356.	2020	MO PSC	Case No. GR-2021-0241	Ameren Missouri Gas	Depreciation
357.	2021	KY PSC	Case No. 2021-00103	East Kentucky Power Cooperative	Depreciation
358.	2021	MPUC	Docket No. 2021-00024	Bangor Natural Gas	Depreciation
359.	2021	PA PUC	Docket No. R-2021-3024296	Columbia Gas of Pennsylvania, Inc.	Depreciation
360.	2021	NC Util. Com.	Doc. No. G-5, Sub 632	Public Service of North Carolina	Depreciation
361.	2021	MO PSC	ER-2021-0240	Ameren Missouri	Depreciation
362.	2021	PA PUC	Docket No. R-2021-3024750	Duquesne Light Company	Depreciation
363.	2021	KS PSC	21-BHCG-418-RTS	Black Hills Kansas Gas	Depreciation
364.	2021	KY PSC	Case No. 2021-00190	Duke Energy Kentucky	Depreciation
365.	2021	OR PSC	Docket UM 2152	Portland General Electric	Depreciation
366.	2021	ILL CC	Docket No. 20-0810	North Shore Gas Company	Depreciation
367.	2021	FERC	ER21-1939-000	Duke Energy Progress	Depreciation
368.	2021	FERC	ER21-1940-000	Duke Energy Carolina	Depreciation
369.	2021	KY PSC	Case No. 2021-00183	NiSource Columbia Gas of Kentucky	Depreciation
370.	2021	MD PSC	Case No. 9664	NiSource Columbia Gas of Maryland	Depreciation
371.	2021	OH PUC	Case No. 21-0596-ST-AIR	Aqua Ohio	Depreciation
372.	2021	PA PUC	Docket No. R-2021-3026116	Hanover Borough Municipal Water Works	Depreciation
373.	2021	OR PSC	UM-2180	Idaho Power Company	Depreciation
374.	2021	ID PUC	Case No. IPC-E-21-18	Idaho Power Company	Depreciation
375.	2021	WPSC	6690-DU-104	Wisconsin Public Service Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
376.	2021	PAPUC	Docket No. R-2021-3026116	Borough of Hanover	Depreciation
377.	2021	OH PUC	Case No. 21-637-GA-AIR; Case No. 21-638-GA-ALT; Case No. 21-639-GA-UNC; Case No. 21-640-GA-AAM	NiSource Columbia Gas of Ohio	Depreciation
378.	2021	TX PUC	Texas PUC Docket No. 52195; SOHA Docket No. 473-21-2606	El Paso Electric	Depreciation
379.	2021	MO PSC	Case No. GR.2021-0108	Spire Missouri	Depreciation
380.	2021	WV PSC	Case No. 21-0215-WS-P	West Virginia American Water Company	Depreciation
381.	2021	FERC	ER21-2736	Duke Energy Carolinas	Depreciation
382.	2021	FERC	ER21-2737	Duke Energy Progress	Depreciation
383.	2021	IN URC	Cause #45621	Northern Indiana Public Service Company	Depreciation
384.	2021	PA PUC	Docket No. R-2021-3026682	City of Lancaster	Depreciation
385.	2021	OH PUC	Case No. 21-887-EL-AIR; Case No. 21-888-EL-ATA; Case No. 889-El-AAM	Duke Energy Ohio	Depreciation
386.	2021	AK PSC	Docket No. 21-097-U	Black Hills Energy Arkansas, Inc.	Depreciation
387.	2021	OK CC	Cause No. PUD202100164	Oklahoma Gas & Electric	Depreciation
388.	2021	FERC	Case ER-22-392-001	El Paso Electric	Depreciation
389.	2021	FERC	Case ER-21-XXX	MidAmerican Electric	Depreciation
390.	2021	PA PUC	Docket Nos. R-2021-3027385, R-2021-3027386	Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc.	Depreciation
391.	2022	FERC	Case ER-22-282-000	El Paso Electric	Depreciation
392.	2022	ILL CC	Docket No. 22-0154	MidAmerican Gas	Depreciation
393.	2022	MO PSC	Case No. ER-2022-0129	Evergy Metro	Depreciation
394.	2022	MO PSC	Case No. ER-2022-0130	Evergy Missouri West	Depreciation
395.	2022	PA PUC	Docket No. R-2022-3031211	NiSource Columbia Gas of Pennsylvania, Inc.	Depreciation
396.	2022	MA DPU	D.P.U. 22-20	The Berkshire Gas Company	Depreciation
397.	2022	PA PUC	R-2022-3031672; R-2022-	Pennsylvania-American Water Company	Depreciation
398.	2022	SD PUC	Docket No. NG22-	MidAmerican Gas	Depreciation
399.	2022	MD PSC	Case No. 9680	NiSource Columbia Gas of Maryland	Depreciation
400.	2022	WYPSC	Docket No. 20003-214-ER-22	Black Hills Energy – Cheyenne Light, Fuel and Power Company	Depreciation
401.	2022	MA DPU	D.P.U. 22.22	NSTAR Electric Company d/b/a Eversource Energy	Depreciation
402.	2022	NC Util Com	Docket No. W-218, Sub 573	Aqua North Carolina, Inc.	Depreciation
403.	2022	OR PUC	UM2213	Northwest Natural Gas	Depreciation
404.	2022	OR PUC	UM2214	Northwest Natural Gas	Depreciation
405.	2022	ME PUC	Docket No. 2022-00152	Central Maine Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
406.	2022	SC PSC	Docket No. 2022-254-E	Duke Energy Progress	Depreciation
407.	2022	NC Util Com	Docket No. E-2, SUB 1300	Duke Energy Progress	Depreciation
408.	2022	IN URC	Cause #45772	Northern Indiana Public Service Company	Depreciation
409.	2022	PA PUC	R-2022-3031340	The York Water Company	Depreciation
410.	2022	PA PUC	R-2022-3032806	The York Water Company	Depreciation
411.	2022	PA PUC	R-2022-3031704	Borough of Ambler	Depreciation
412.	2022	MO PSC	ER-2022-0337	Ameren Missouri	Depreciation
413.	2022	OH PUC	Case No. 22-507-GA-AIR	Duke Energy Ohio	Depreciation
414.	2022	PA PUC	R-2022-3035730	National Fuel Gas Distribution Corporation – PA Division	Depreciation
415.	2022	WY PSC	20003-214-ER-22	Cheyenne Light, Fuel and Power Company	Depreciation
416.	2022	NJ BPU	BPU Docket No.	Jersey Central Power & Light Company	Depreciation
417.	2022	KY PSC	Case No. 2022-00372	Duke Energy Kentucky	Depreciation
418.	2022	TX PUC	SOAH Docket No. 473-23-04521	Aqua Texas, Inc.	Depreciation
419.	2022	NC Util Com	Docket No. E-7, Sub 1276	Duke Energy Carolinas, LLC	Depreciation
420.	2022	ILL CC	Docket No. 23-0069	The Peoples Gas Light and Coke Company	Depreciation
421.	2023	ILL CC	Docket No. 23-0068	North Shore Gas Company	Depreciation
422.	2023	WV PSC	Case No. 23-0030-E-D	Monongahela Power Company and The Potomac Edison Company	Depreciation
423.	2023	ID PUC	AVU-E-23-01; AVU-G-23-01	Avista Corporation	Depreciation
424.	2023	ILL CC	Docket No. 23-	Northern Illinois Gas Company d/b/a Nicor Gas Company	Depreciation

PotomacEdison®
A FirstEnergy Company

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AS OF JUNE 30, 2022

Prepared by:

GANNETT FLEMING
Excellence Delivered As Promised

THE POTOMAC EDISON COMPANY

Williamsport, Maryland

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AS OF JUNE 30, 2022

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Camp Hill, Pennsylvania

GANNETT FLEMING

Gannett Fleming
Valuation and Rate Consultants, LLC

Corporate Headquarters
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Camp Hill, PA 17011
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gannettfleming.com

March 21, 2023

The Potomac Edison Company
10802 Bower Avenue
Williamsport, MD 21795

Attention Raymond E. Valdes
Director, Rates & Regulatory Affairs – WV/MD

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric plant in service of The Potomac Edison Company Maryland assets as of June 30, 2022. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual and accrued depreciation, the statistical support for the service life and net salvage estimates, and the detailed tabulations of annual and accrued depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John J Spanos

JOHN J. SPANOS
President

JJS:mle

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THE POTOMAC EDISON COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to The Potomac Edison Company's ("Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the electric plant as of June 30, 2022. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life and forecasted net salvage characteristics for each depreciable group of assets.

For most accounts, the service lives proposed in this depreciation study are similar to those that were proposed by the Company in the prior study. The data and Company information received since the last depreciation study support these service lives. There have been some changes in the life estimates which produce some longer lives and some shorter lives. For net salvage the proposed estimates are typically more negative than what was approved in the last study which is due to the required costs to remove assets from service. Also, the currently approved net salvage estimates are based on a present value method used only in Maryland (the "MD Present Value Method"). This method along with the net salvage estimates have been significantly deficient at recovering the net salvage costs the Company has incurred.

The Company proposed rates from the Appendix of the depreciation study use the MD Present Value Method with a discount rate based on the credit-adjusted risk-free rate (CARFR). Gannett Fleming does not support this method for calculating net salvage accruals, however due to Commission precedent it has been decided that the proposed rates should be calculated using the MD Present Value Method with the CARFR as the discount rate.

Gannett Fleming continues to recommend the traditional method as the most appropriate method for the recovery of net salvage. The resultant depreciation rates for electric plant in service as of June 30, 2022 are summarized in Table 1 on pages VI-4 and VI-5 of the study. Supporting analysis and calculations are provided within the study. Additionally, depreciation rates based on the MD Present Value Method using a credit-adjusted risk-free rate are provided in the Appendix to this report which is consistent with recent precedent in . The depreciation rates set forth in the Appendix are the most reasonable rates that align with the use of the MD Present Value Method.

The study results from the Appendix set forth an annual depreciation expense of $31.8 million when applied to depreciable plant balances as of June 30, 2022. The results are summarized at the functional level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST AS OF JUNE 30, 2022	PROPOSED RATE	PROPOSED EXPENSE
Intangible Plant	$ 25,518,930.61	**7.21**	$ 1,839,674
Distribution Plant	1,305,686,527.16	**2.11**	27,496,130
General Plant	67,532,573.45	**3.70**	2,496,259
Total	**$1,398,738,031.26**		**$31,832,063**

PART I. INTRODUCTION

THE POTOMAC EDISON COMPANY
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for The Potomac Edison Company ("Company"), as applied to electric plant in service as of June 30, 2022. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to current electric plant in service.

The service life and net salvage estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through June 2022; the net salvage analyses of historical plant retirement data recorded through June 2022; a review of Company practice and outlook as they relate to plant operation and retirement; and consideration of current practice in the electric industry, including knowledge of service lives and net salvage estimates used for other electric companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life study. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, presents the judgment utilized for the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents a summary by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics, presents the statistical analysis of service life estimates, Part VIII, Net Salvage Statistics, sets forth the statistical indications of net salvage percents, and Part IX, Detailed Depreciation Calculations, presents the detailed tabulations of annual depreciation.

BASIS OF THE STUDY

Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

For most accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. For certain General Plant accounts, the annual depreciation is based on amortization accounting. Both types of calculations were based on original cost, attained ages, and estimates of service lives and net salvage. The straight line method, average service life procedure is the most commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. An explanation of the calculation of annual and accrued amortization is presented beginning on page V-4 of the report.

Service Life and Net Salvage Estimates

The service life and net salvage estimates used in the depreciation calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and net salvage estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility property. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The estimates of net salvage by account incorporated a review of experienced costs of removal and gross salvage related to plant retirements, and consideration of trends exhibited by the historical data. Each component of net salvage, i.e., cost of removal and gross salvage, was stated in dollars and as a percent of retirement.

An understanding of the function of the plant and information with respect to the reasons for past retirements and the expected causes of future retirements was obtained through discussions with operating and management personnel. The supplemental information obtained in this manner was considered in the interpretation and extrapolation of the statistical analyses.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may 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 successive 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 calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating 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 calculated 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 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves 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 which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

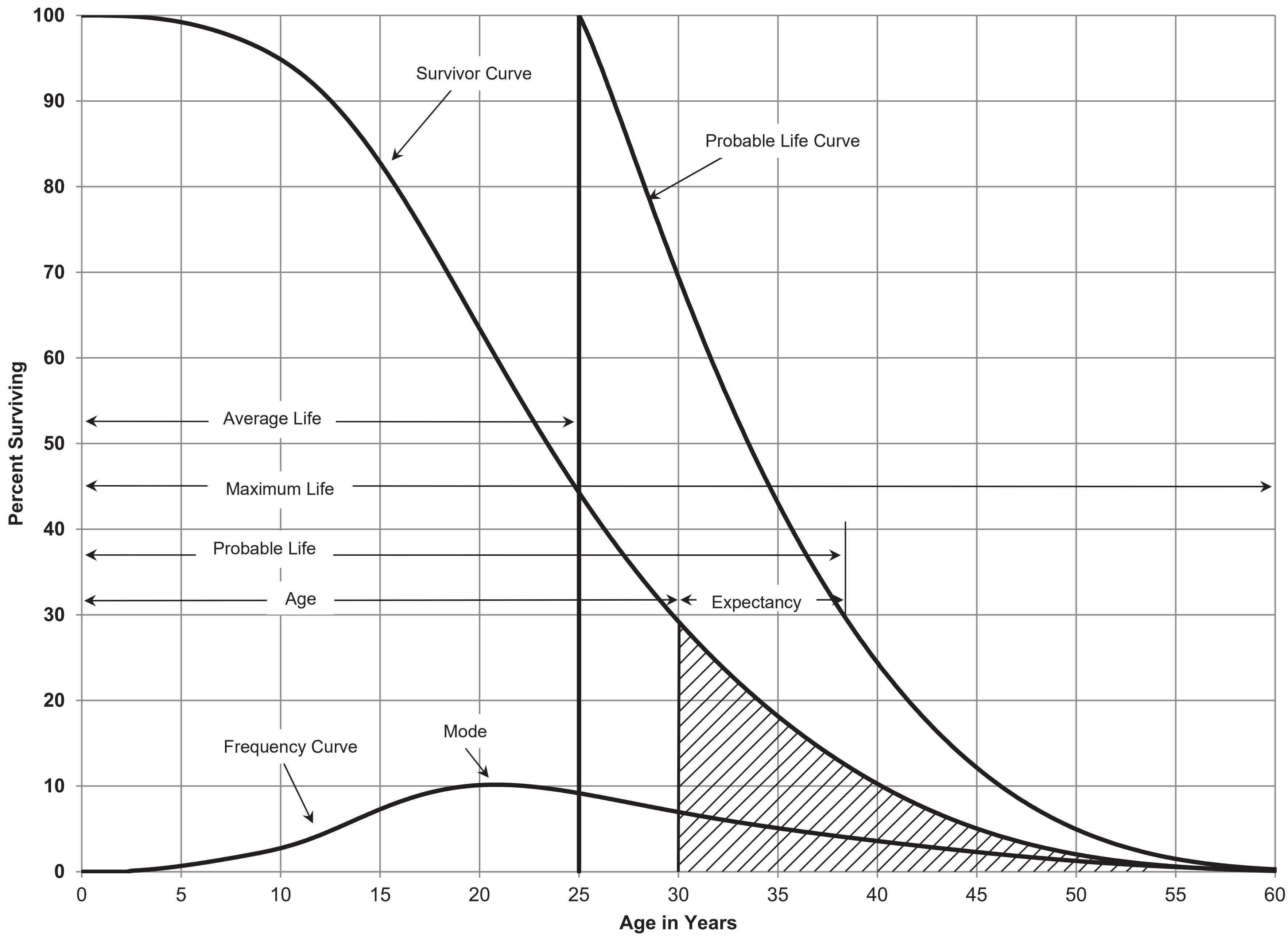

FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

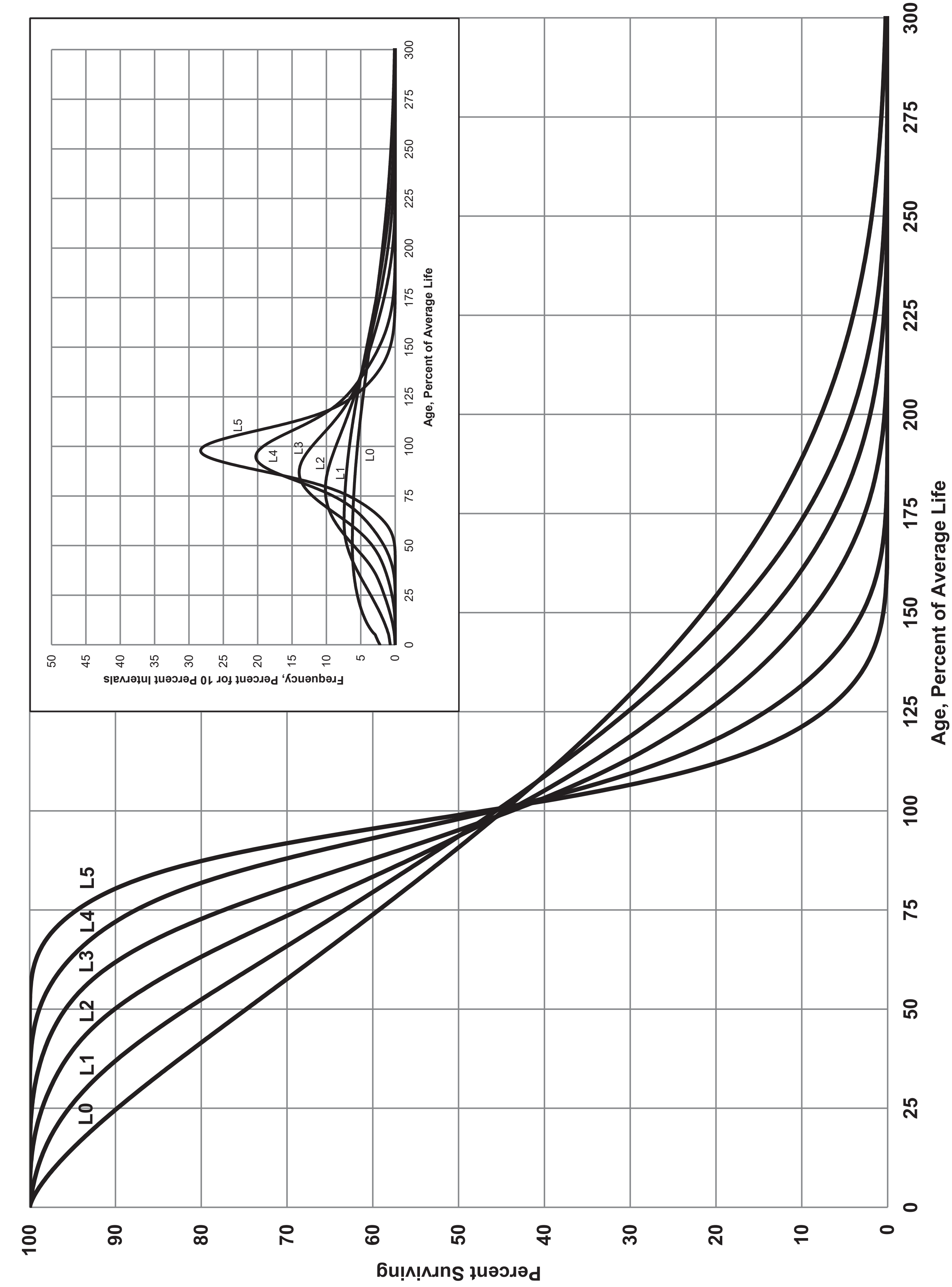

FIGURE 2.. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

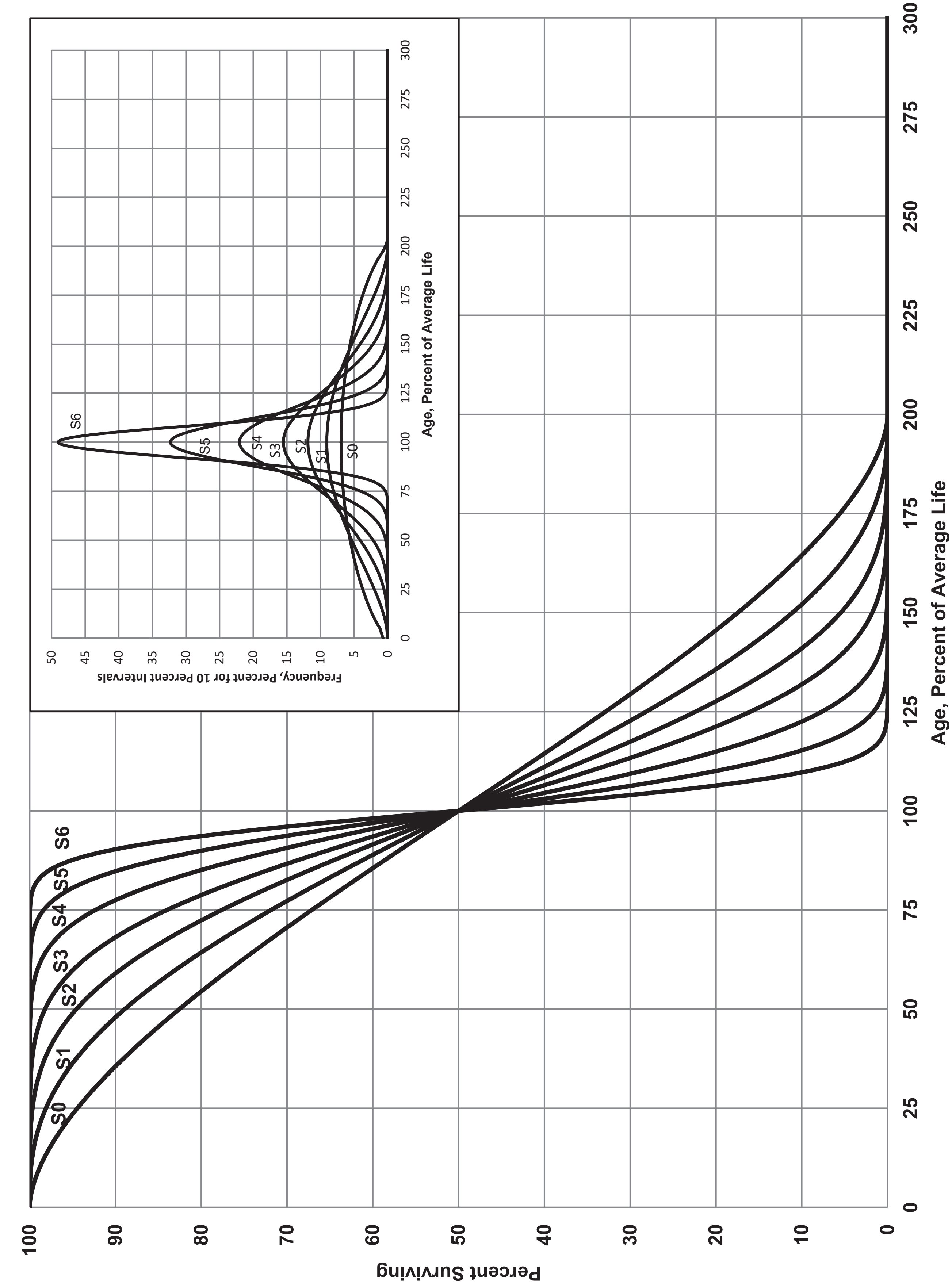

FIGURE 3.. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

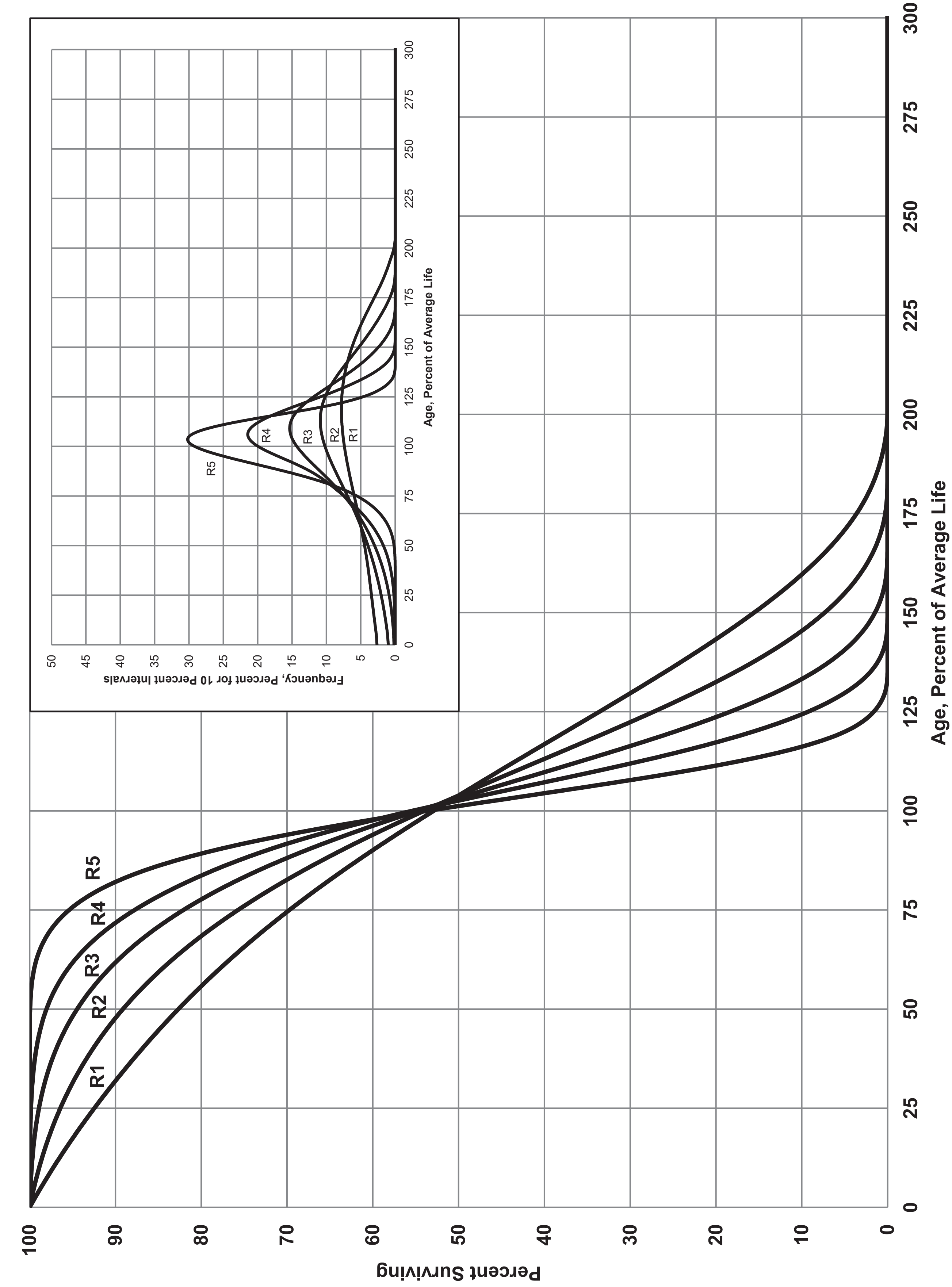

FIGURE 4.. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

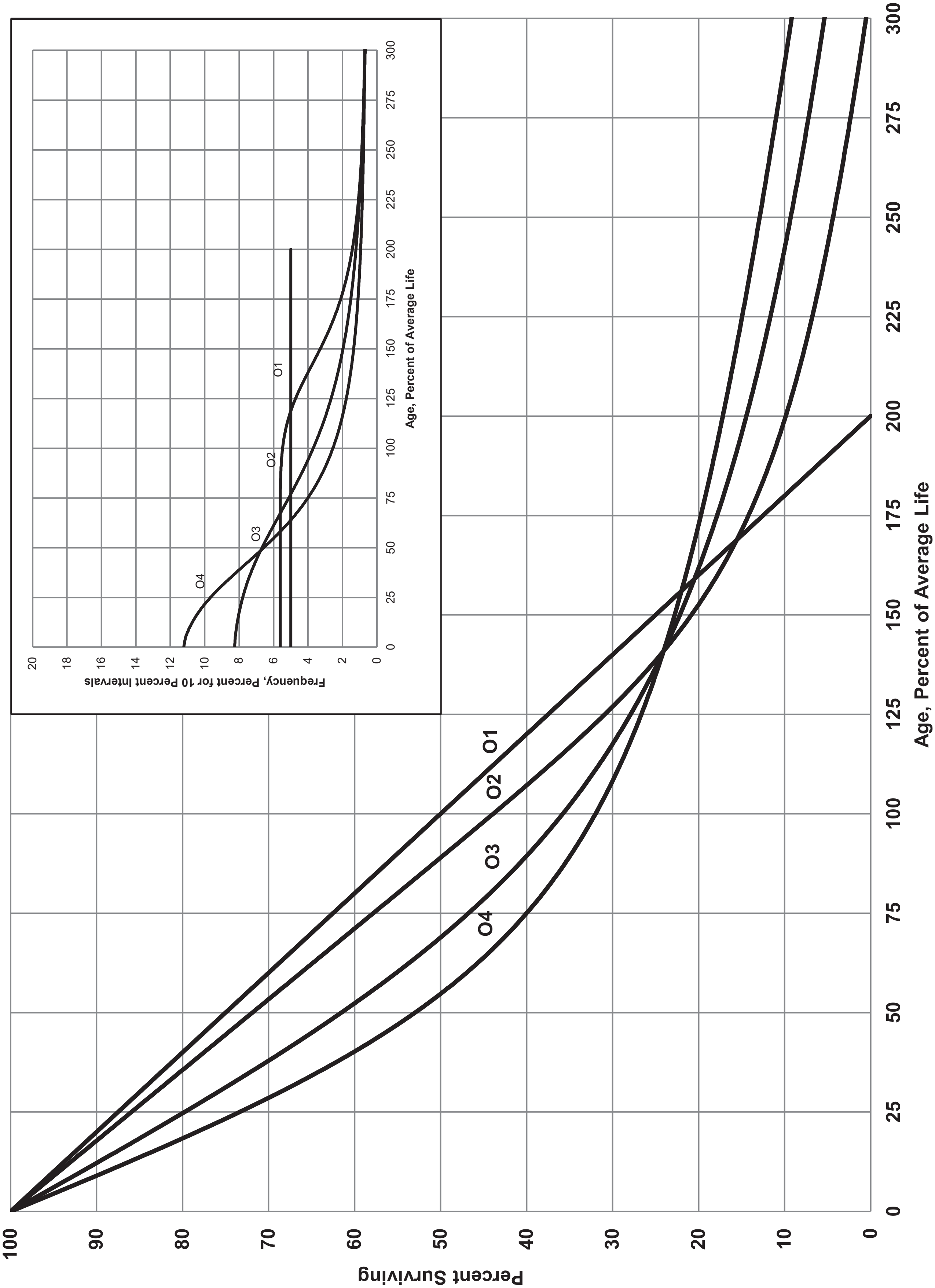

FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text and is also explained in several publications including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band. The band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

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[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.

[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2013-2022 for which there were placements during the years 2008-2022. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2008 were retired in 2013. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2013 retirements of 2008 installations and ending with the 2022 retirements of the 2017 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022

Placement Band 2008-2022

Year Placed (1)	2013 (2)	2014 (3)	2015 (4)	2016 (5)	2017 (6)	2018 (7)	2019 (8)	2020 (9)	2021 (10)	2022 (11)	Total During Age Interval (12)	Age Interval (13)
	Retirements, Thousands of Dollars During Year											
2008	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2009	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2010	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2011	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2012	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2013	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2014		5	11	12	13	14	15	16	18	20	113	7½-8½
2015			6	12	13	15	16	17	19	19	124	6½-7½
2016				6	13	15	16	17	19	19	131	5½-6½
2017					7	14	16	17	19	20	143	4½-5½
2018						8	18	20	22	23	146	3½-4½
2019							9	20	22	25	150	2½-3½
2020								11	23	25	151	1½-2½
2021									11	24	153	½-1½
2022										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 — Placement Band 2008-2022

Year Placed (1)	2013 (2)	2014 (3)	2015 (4)	2016 (5)	2017 (6)	2018 (7)	2019 (8)	2020 (9)	2021 (10)	2022 (11)	Total During Age Interval (12)	Age Interval (13)
	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
2008	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2009	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2010	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2011	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2012	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2013	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2014		-	-	-	-	-	-	-	-	-	6	7½-8½
2015			-	-	-	-	-	-	-	-	-	6½-7½
2016				-	-	-	-	(12)[b]	-	-	-	5½-6½
2017					-	-	-	-	22[a]	-	-	4½-5½
2018						-	-	(19)[b]	-	-	10	3½-4½
2019							-	-	-	-	-	2½-3½
2020								-	-	(102)[c]	(121)	1½-2½
2021									-	-	-	½-1½
2022											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2013 through 2022 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition 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, transfers-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 transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2018 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 | Placement Band 2008-2022

	Exposures, Thousands of Dollars											
	Annual Survivors at the Beginning of the Year										Total at	
Year Placed	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Beginning of Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2009	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2010	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2011	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2012	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2013	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2014		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2015			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2016				580[a]	574	561	546	530	501	482	3,057	5½-6½
2017					660[a]	653	639	623	628	609	3,789	4½-5½
2018						750[a]	742	724	685	663	4,332	3½-4½
2019							850[a]	841	821	799	4,955	2½-3½
2020								960[a]	949	926	5,719	1½-2½
2021									1,080[a]	1,069	6,579	½-1½
2022										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2013-2022, 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 (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. 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, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2013-2022 Placement Band 2008-2022

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

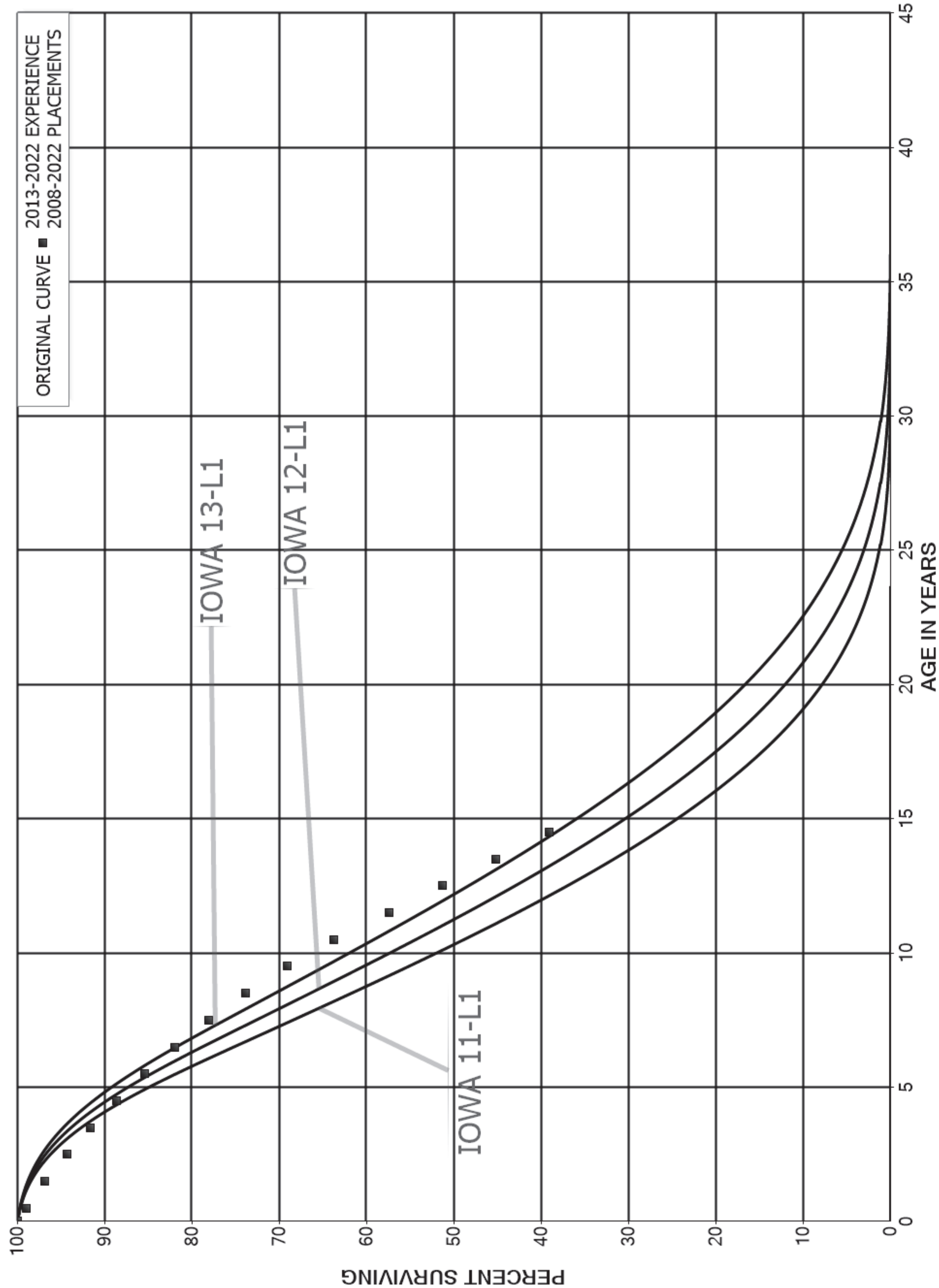


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

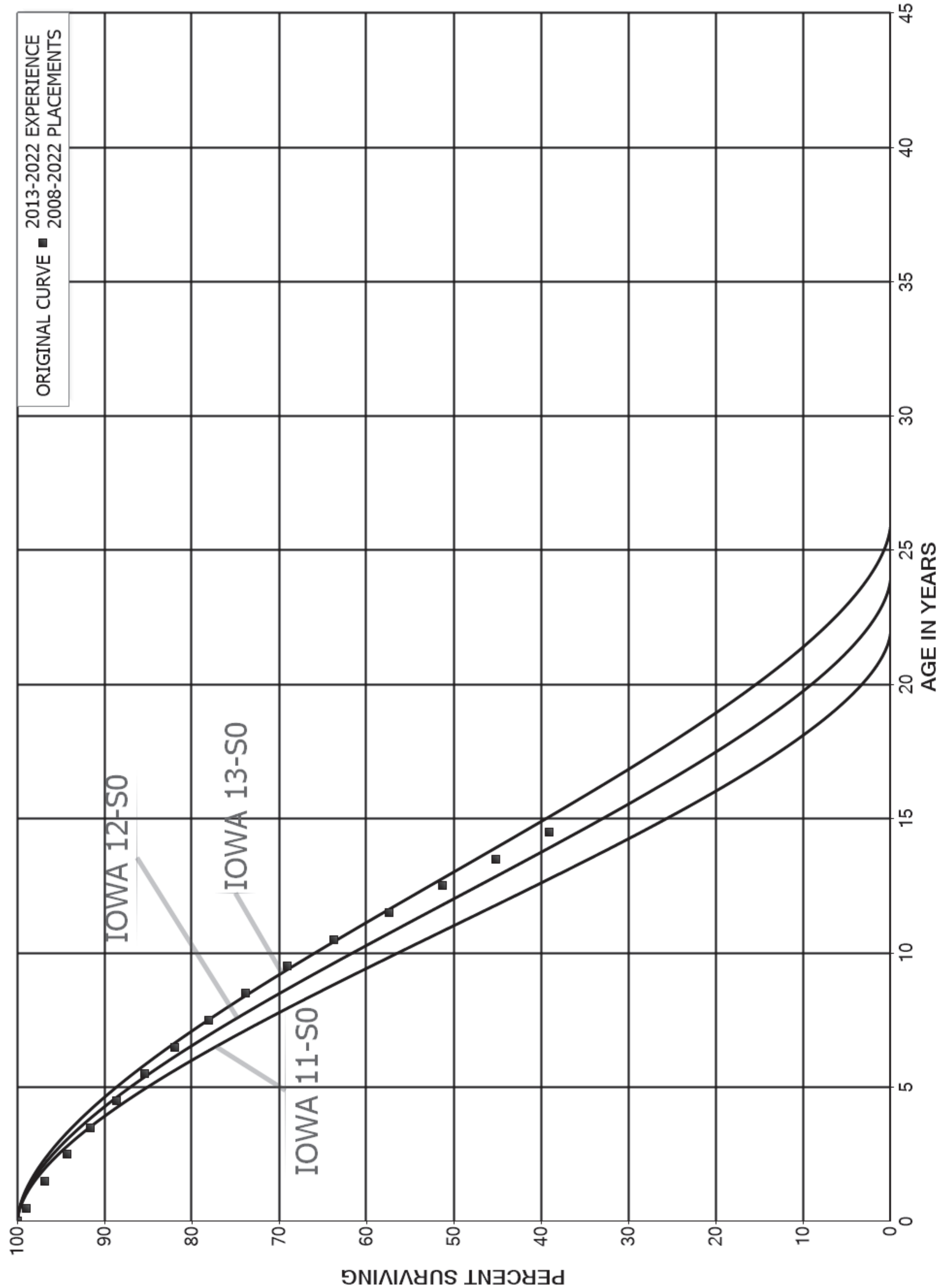


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

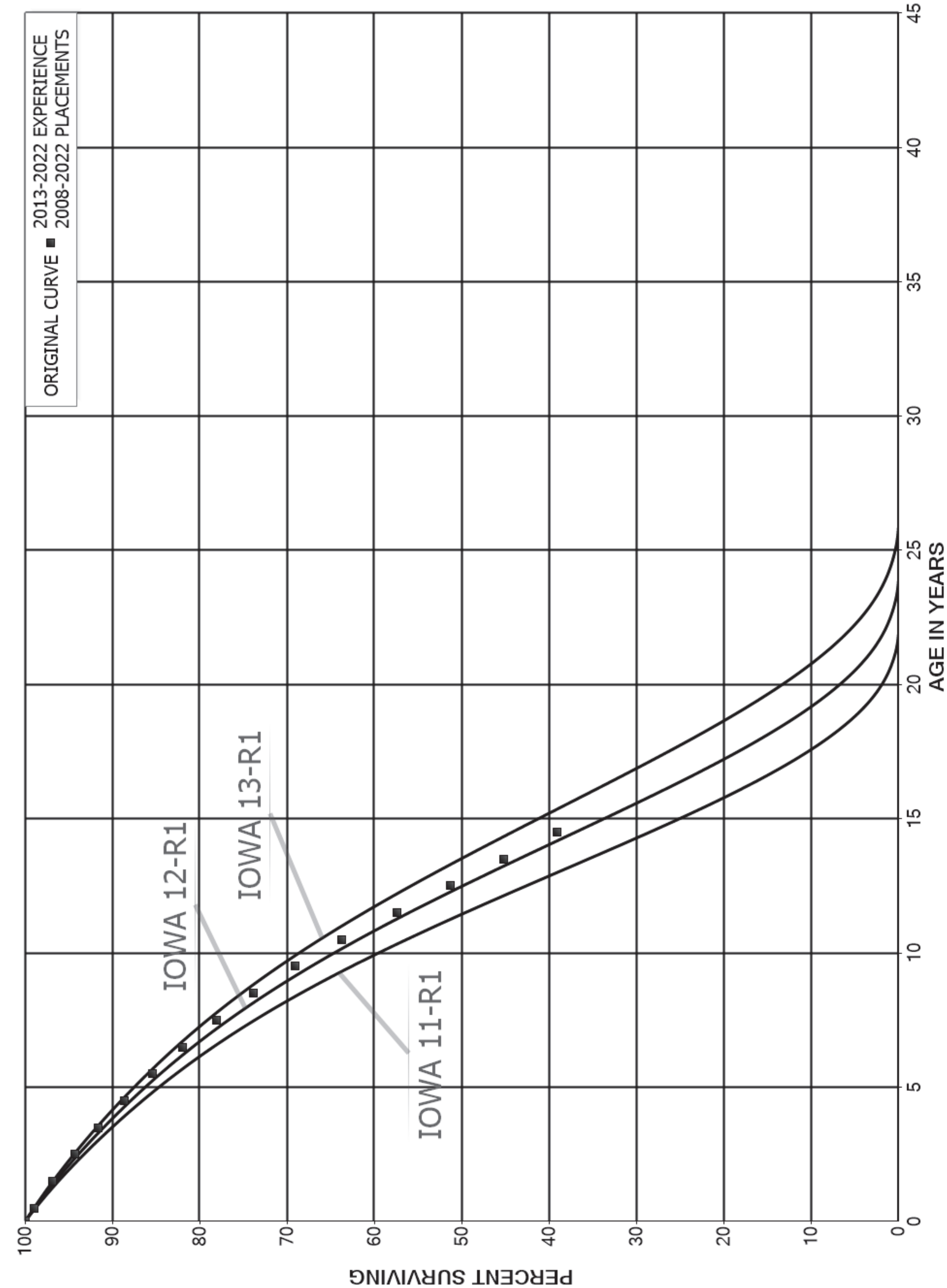
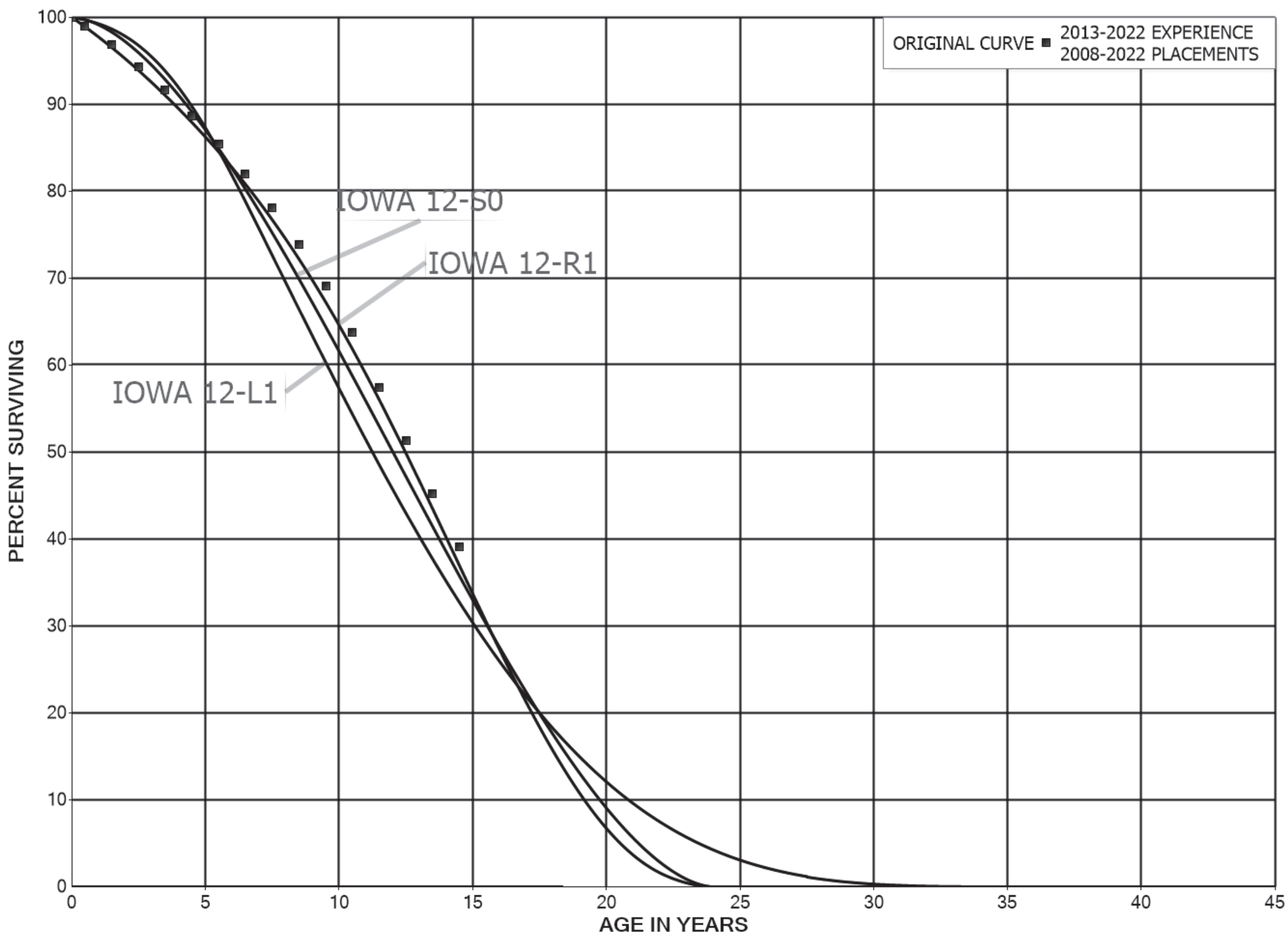


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

In order to be familiar with the operation of the Company and to observe representative portions of the plant, a field trip was conducted. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements was obtained during this trip. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The plant facilities visited on the most recent field trip are as follows:

February 6, 2022
- Frederick Service Center
- Cabin Branch Substation
- Crystal Rock Substation
- Lime Kiln Substation

July 30, 2020
- Williamsport Service Center
- Halfway Substation
- General Office Substation
- Maple Avenue Substation
- Garfield Substation
- Frederick A Substation
- Frederick Service Center

SERVICE LIFE ANALYSIS

The service life estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data, current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric utility companies.

For 10 plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good to excellent indications of the survivor patterns experienced. Generally, the information external to the statistics led to minimal or no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

DISTRIBUTION PLANT

362.00	Station Equipment
364.00	Poles, Towers and Fixtures
365.00	Overhead Conductors and Devices
367.00	Underground Conductors and Devices
368.00	Line Transformers
369.00	Services
370.00	Meters
373.10	Street Lighting and Signal Systems

GENERAL PLANT

390.10	Structures and Improvements
392.00	Transportation Equipment

Account 368.00, Line Transformers, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Aged plant accounting data for line transformers have been compiled for the years 1997 through June 2022. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate is based on the statistical indications for the period 1997 through June 2022. The Iowa 50-R1.5 is a reasonable fit of the original survivor curve. The 50-year service life is at the upper end of the typical service life range of 35 to 50 years for line transformers. The 50-year life reflects the Company's plans to continue current practices of replacement for newer technology or high load needs and increase of padmounted transformers.

The currently approved estimate for Account 362.00 Station Equipment is the 75-R1.5. The 65-R2.5 is a good fit of the data through age 45.5 which represents the most relevant portion of the original life table. The plant exposed to retirement at ages older than that are less than ideal for this type of property, especially considering the large amount of exposures through the youngest few age intervals. For station equipment, the emphasis on high level exposures in appropriate due to the cost of significant assets, such as transformers. Within the industry, the range of average service lives is 45-60 years based on the nature of the assets so longer than 60 years is not appropriate.

The survivor curve estimates for the remaining accounts were based on judgment incorporating the statistical analyses and previous studies for this and other electric utilities.

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

NET SALVAGE ANALYSIS

The estimates of net salvage by account were based in part on historical data compiled through June 2022. Cost of removal and gross salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

Net Salvage Considerations

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and gross salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and gross salvage data are presented in the section titled “Net Salvage Statistics” for the plant accounts for which the net salvage estimate relied partially on those analyses.

Statistical analyses of historical data for the period 2001 through June 2022 for electric plant were analyzed. The analyses contributed significantly toward the net salvage estimates for 10 plant accounts and subaccount of the depreciable plant, as follows:

DISTRIBUTION PLANT

362.00	Station Equipment
365.00	Overhead Conductors and Devices
366.00	Underground Conduit
367.00	Underground Conductors and Devices

368.00	Line Transformers
370.00	Meters
371.00	Installations on Customers' Premises
373.10	Street Lighting and Signal Systems

GENERAL PLANT

390.10	Structures and Improvements
392.00	Transportation Equipment

Account 362.00, Station Equipment, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Net salvage data for the period 2001 through June of 2022 were analyzed for this account. The data include cost of removal, gross salvage and net salvage amounts and each of these amounts is expressed as a percent of the original cost of regular retirements. Three-year moving averages for the 2001-2003 through 2020-2022 periods were computed to smooth the annual amounts.

Cost of removal has fluctuated throughout the twenty-two year period with a trend higher in the last few years. The primary cause of the fluctuations in cost of removal relates to the type and size of the station equipment removed each year. The large projects or inside the building assets have lower cost to remove per asset. Cost of removal for the most recent five years averaged 60 percent.

Gross salvage has also varied throughout the period, however, in most years has been zero. The most recent five-year average of 1 percent gross salvage reflects recent lower salvage value of station equipment.

The net salvage percent based on the overall period 2001 through June 2022 is 15 percent negative net salvage and based on the most recent five-year period is negative 59 percent. This shows a trend towards more negative net salvage. The range of estimates made by other electric companies for Station Equipment is negative 5 to negative 25 percent. The net salvage estimate for station equipment is negative 20 percent, is within the range of other estimates and reflects the trend in recent years of more negative net salvage.

The net salvage percents for the remaining accounts of plant were based on judgment incorporating estimates of previous studies of this and other electric utilities.

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. Normally 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, namely, 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 balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent 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 accrual 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

For the purpose of calculating remaining life accruals as of June 30, 2022, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of June 30, 2022, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization, as defined in the Uniform System of Accounts, is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization periods and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is appropriate for certain General and Common Plant accounts that represent numerous units of property, but a very small portion of total depreciable electric plant in service. The accounts and their amortization periods are as follows:

General Plant	Account	Amortization Period, Years
391.00	Office Furniture and Equipment – Furniture	20
391.15	Office Furniture and Equipment – Equipment	10
391.20	Office Furniture and Equipment – Personal Computers	10
393.00	Stores Equipment	20
394.00	Tools, Shop and Garage Equipment	20
395.00	Laboratory Equipment	20
397.00	Communication Equipment	10
398.00	Miscellaneous Equipment	15

For the purpose of calculating annual amortization amounts as of June 30, 2022, the book 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's 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's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (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 and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged implies service lives, net salvage percentages and the change in the composition of property in service will not change. 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 considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the electric plant in service as of June 30, 2022 and the application of such rates to future balances that reflect additions subsequent to June 30, 2022.

DESCRIPTION OF STATISTICAL SUPPORT

The service life and net salvage estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management and consideration of estimates made for other electric utility companies. The results of the statistical analyses of service life are presented in the section titled "Service Life Statistics".

The estimated survivor curves for each account are presented in graphical form. The charts depict the estimated smooth survivor curve and original survivor curve(s), when applicable, related to each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

The analyses of net salvage data are presented in the section titled, "Net Salvage Statistics". The tabulations present annual cost of removal and gross salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study using the traditional method for net salvage, as applied to the original cost of electric plant as of June 30, 2022, is presented on page VI-4. The schedule sets forth the original cost, the book reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to electric plant.

The tables of the calculated annual depreciation accruals are presented in account sequence in the section titled "Detailed Depreciation Calculations." The tables indicate the estimated survivor curve and net salvage percent for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life and the calculated annual accrual amount. The Appendix of this report provides proposed depreciation rates and accruals using the MD Present Value Method for net salvage that has previously been used only in Maryland. A credit-adjusted risk-free rate of 5.93% was established for these calculations.

THE POTOMAC EDISON COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF JUNE 30, 2022

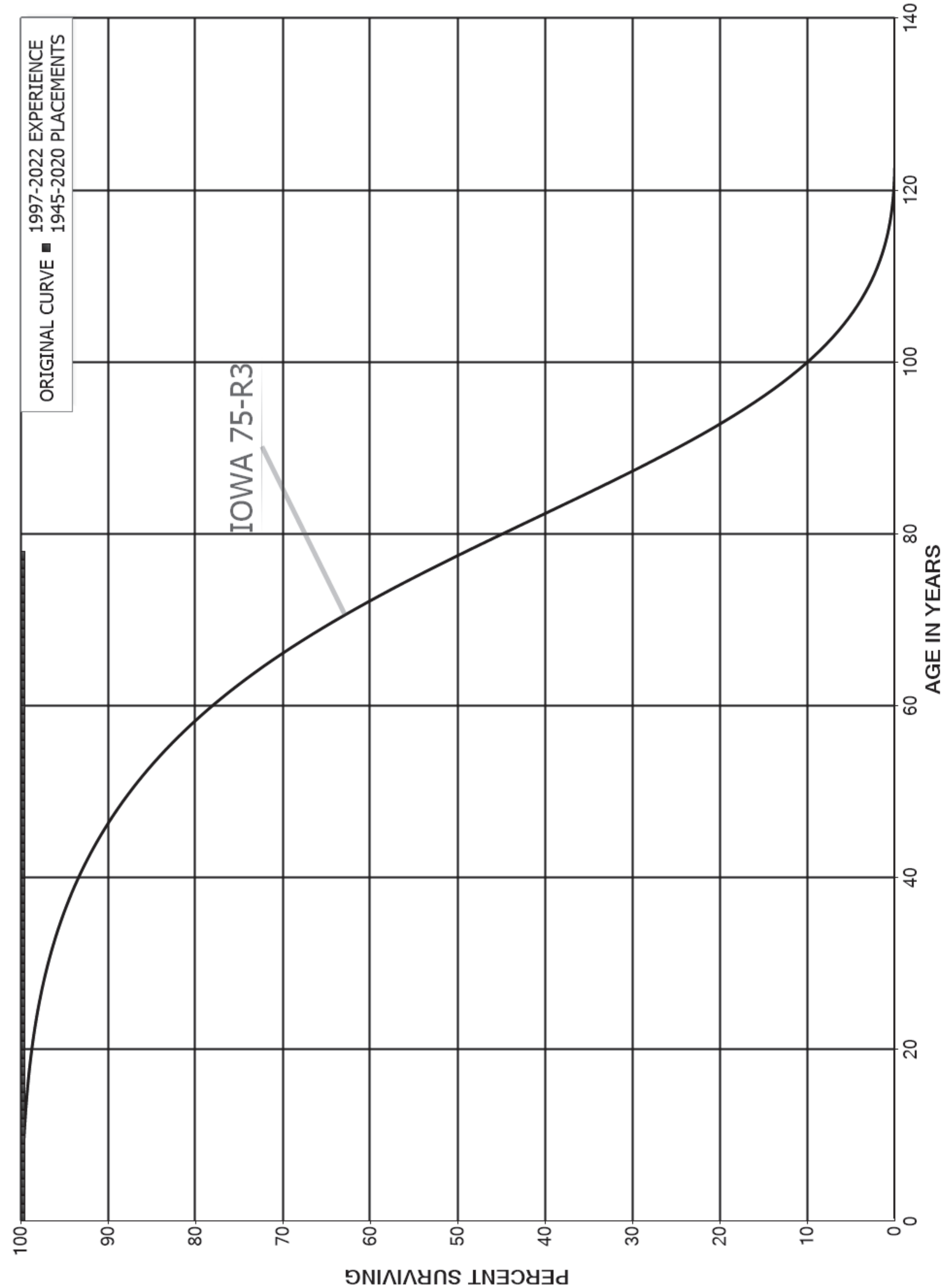
	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT	ORIGINAL COST AS OF JUNE 30, 2022 (3)	BOOK DEPRECIATION RESERVE (4)	FUTURE ACCRUALS (5)	CALCULATED ANNUAL ACCRUAL AMOUNT (6)	CALCULATED ANNUAL ACCRUAL RATE (7)=(6)/(3)	COMPOSITE REMAINING LIFE (8)=(5)/(6)
	ELECTRIC PLANT								
	INTANGIBLE PLANT								
303.00	MISCELLANEOUS INTANGIBLE PLANT	7-SQ	0	25,518,930.61	18,333,018	7,185,913	1,839,674	7.21	3.9
	TOTAL INTANGIBLE PLANT			**25,518,930.61**	**18,333,018**	**7,185,913**	**1,839,674**	**7.21**	**3.9**
	DISTRIBUTION PLANT								
360.20	LAND AND LAND RIGHTS - EASEMENTS	75-R3	0	10,999,110.61	3,156,497	7,842,614	143,090	1.30	54.8
361.00	STRUCTURES AND IMPROVEMENTS	65-S4	(20)	11,344,560.25	5,716,535	7,896,937	172,709	1.52	45.7
362.00	STATION EQUIPMENT	65-R2.5	(20)	186,933,531.24	70,335,515	153,984,723	3,042,731	1.63	50.6
364.00	POLES, TOWERS AND FIXTURES	70-R4	(125)	131,651,738.90	70,244,646	225,971,766	4,620,624	3.51	48.9
365.00	OVERHEAD CONDUCTORS AND DEVICES	62-R1	(100)	151,495,917.54	40,460,712	262,531,123	5,315,360	3.51	49.4
365.10	OVERHEAD CONDUCTORS AND DEVICES - CLEARING	70-R4	0	77,713,677.02	16,600,546	61,113,131	969,012	1.25	63.1
366.00	UNDERGROUND CONDUIT	65-R4	(50)	66,754,673.86	29,932,474	70,199,537	1,574,419	2.36	44.6
367.00	UNDERGROUND CONDUCTORS AND DEVICES	44-R3	(50)	300,720,151.61	95,460,244	355,619,984	12,071,055	4.01	29.5
368.00	LINE TRANSFORMERS	50-R1.5	(35)	204,527,694.78	101,500,754	174,611,634	4,749,630	2.32	36.8
369.00	SERVICES	65-R4	(125)	73,021,590.19	53,923,896	110,374,681	2,573,714	3.52	42.9
370.00	METERS	42-R2.5	(30)	56,802,201.89	26,390,587	47,452,275	1,635,599	2.88	29.0
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	30-R0.5	(40)	2,165,322.14	747,090	2,284,361	151,440	6.99	15.1
373.10	STREET LIGHTING AND SIGNAL SYSTEMS	44-S0.5	(45)	31,556,357.13	12,099,229	33,657,489	1,049,421	3.33	32.1
	TOTAL DISTRIBUTION PLANT			**1,305,686,527.16**	**526,568,725**	**1,513,540,255**	**38,068,804**	**2.92**	**39.8**
	GENERAL PLANT								
389.20	LAND RIGHTS	75-R3	0	3,778.48	859	2,920	50	1.32	58.4
390.10	STRUCTURES AND IMPROVEMENTS	60-R2	(15)	27,398,563.95	12,299,682	19,208,667	427,466	1.56	44.9
391.00	OFFICE FURNITURE AND EQUIPMENT - OFFICE FURNITURE	20-SQ	0	2,932,525.30	1,806,999	1,125,526	107,892	3.68	10.4
391.15	OFFICE FURNITURE AND EQUIPMENT - OFFICE EQUIPMENT	10-SQ	0	288,466.27	288,466	0	0	- *	-
391.20	OFFICE FURNITURE AND EQUIPMENT - PERSONAL COMPUTERS	10-SQ	0	2,830,756.55	229,419	2,601,337	493,016	17.42	5.30
392.00	TRANSPORTATION EQUIPMENT	13-L2	20	4,428,477.06	2,236,225	1,306,557	124,550	2.81	10.5
393.00	STORES EQUIPMENT	20-SQ	0	162,237.13	132,644	29,593	1,866	1.15	15.9
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	20-SQ	0	9,248,862.82	3,648,702	5,600,161	425,310	4.60	13.2
395.00	LABORATORY EQUIPMENT	20-SQ	0	726,981.47	646,524	80,457	13,456	1.85	6.00
396.00	POWER OPERATED EQUIPMENT	20-S0.5	5	844,671.75	806,011	(3,573)	0	- **	0.0
397.00	COMMUNICATION EQUIPMENT	10-SQ	0	18,506,167.11	11,455,947	7,050,220	973,325	5.26	7.2
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	0	161,085.56	159,585	1,501	946	0.59	1.6
	TOTAL GENERAL PLANT			**67,532,573.45**	**33,711,063**	**37,003,366**	**2,567,877**	**3.80**	**14.4**
	TOTAL DEPRECIABLE PLANT			**1,398,738,031.22**	**578,612,806**	**1,557,729,534**	**42,476,355**	**3.04**	**36.7**
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED								
301.00	ORGANIZATION			124,448.78					
360.10	LAND AND LAND RIGHTS - LAND			11,931,025.07					
389.10	LAND AND LAND RIGHTS - LAND			1,382,979.33					
399.10	ASSET RETIREMENT COSTS - GENERAL PLANT			14,235.89	11,197				
	TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED			**13,452,689.07**	**11,197**				
	TOTAL ELECTRIC PLANT			**1,412,190,720.29**	**578,624,003**				

* FOR NEW ADDITIONS TO ACCOUNT 391.15 OFFICE FURNITURE AND EQUIPMENT - OFFICE EQUIPMENT A 10.00% DEPRECIATION RATE IS RECOMMENDED BASED ON A 10-SQ AND 0 PERCENT NET SALVAGE
** FOR NEW ADDITIONS TO ACCOUNT 396.00 POWER OPERATED EQUIPMENT A 4.75% DEPRECIATION RATE IS RECOMMENDED BASED ON A 20-S0.5 SURVIVOR CURVE AND 5 PERCENT NET SALVAGE

NOTE: THE ANNUAL ACCRUAL RATE FOR NEW ADDITIONS AS OF JULY 1, 2022 ARE AS FOLLOWS:
ACCOUNT 363.00, ELECTRIC STORAGE BATTERY ACCRUAL RATE IS 6.67% BASED ON A 15-L3 SURVIVOR CURVE AND 0% NET SALVAGE
ACCOUNT 371.10, ELECTRIC VEHICLE CHARGING STATIONS ACCRUAL RATE IS 10.00% BASED ON A 10-S3 SURVIVOR CURVE AND 0% NET SALVAGE

PART VII. SERVICE LIFE STATISTICS

THE POTOMAC EDISON COMPANY
ACCOUNT 360.20 LAND AND LAND RIGHTS - EASEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 360.20 LAND AND LAND RIGHTS - EASEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1945-2020 EXPERIENCE BAND 1997-2022

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	7,497,675		0.0000	1.0000	100.00
0.5	7,604,588		0.0000	1.0000	100.00
1.5	8,311,828		0.0000	1.0000	100.00
2.5	8,334,623		0.0000	1.0000	100.00
3.5	8,535,282		0.0000	1.0000	100.00
4.5	7,390,455		0.0000	1.0000	100.00
5.5	7,514,232		0.0000	1.0000	100.00
6.5	7,581,105		0.0000	1.0000	100.00
7.5	7,620,976		0.0000	1.0000	100.00
8.5	7,644,676		0.0000	1.0000	100.00
9.5	7,664,487		0.0000	1.0000	100.00
10.5	7,416,769		0.0000	1.0000	100.00
11.5	6,424,447		0.0000	1.0000	100.00
12.5	4,767,158		0.0000	1.0000	100.00
13.5	4,806,260		0.0000	1.0000	100.00
14.5	3,836,838		0.0000	1.0000	100.00
15.5	2,930,522		0.0000	1.0000	100.00
16.5	3,011,500		0.0000	1.0000	100.00
17.5	2,427,589		0.0000	1.0000	100.00
18.5	2,418,332		0.0000	1.0000	100.00
19.5	2,311,722		0.0000	1.0000	100.00
20.5	2,334,168		0.0000	1.0000	100.00
21.5	2,337,151		0.0000	1.0000	100.00
22.5	2,227,469		0.0000	1.0000	100.00
23.5	2,243,375		0.0000	1.0000	100.00
24.5	2,211,994		0.0000	1.0000	100.00
25.5	2,105,003		0.0000	1.0000	100.00
26.5	2,072,024		0.0000	1.0000	100.00
27.5	1,406,894		0.0000	1.0000	100.00
28.5	1,460,964		0.0000	1.0000	100.00
29.5	1,522,018		0.0000	1.0000	100.00
30.5	1,516,468		0.0000	1.0000	100.00
31.5	1,425,221		0.0000	1.0000	100.00
32.5	1,397,161		0.0000	1.0000	100.00
33.5	1,412,361		0.0000	1.0000	100.00
34.5	1,436,238		0.0000	1.0000	100.00
35.5	1,496,297		0.0000	1.0000	100.00
36.5	1,463,262		0.0000	1.0000	100.00
37.5	1,476,180	20	0.0000	1.0000	100.00
38.5	1,524,214		0.0000	1.0000	100.00

THE POTOMAC EDISON COMPANY

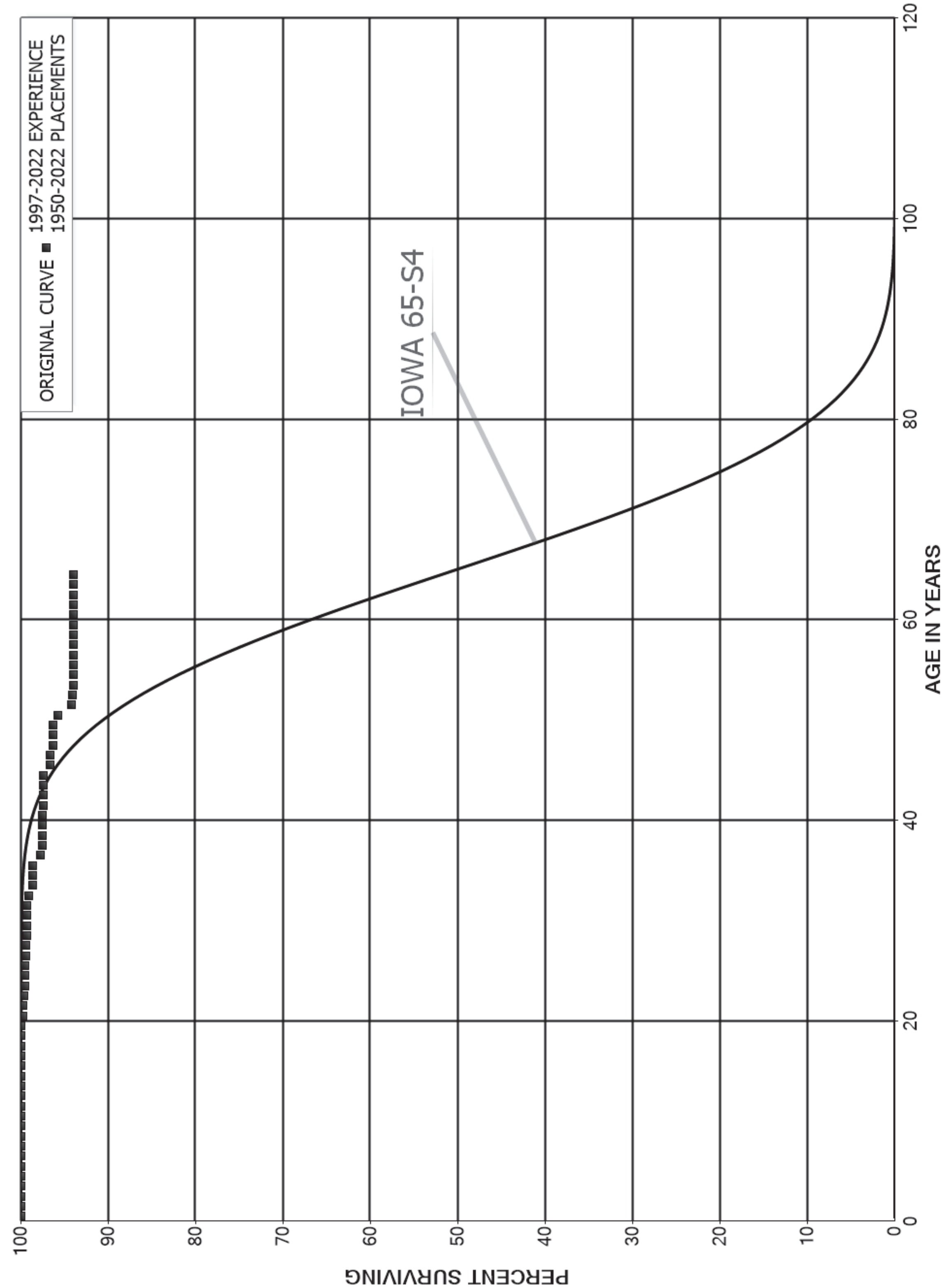
ACCOUNT 360.20 LAND AND LAND RIGHTS - EASEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1945-2020 EXPERIENCE BAND 1997-2022

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	1,502,281		0.0000	1.0000	100.00
40.5	1,435,936		0.0000	1.0000	100.00
41.5	1,347,299		0.0000	1.0000	100.00
42.5	1,298,115		0.0000	1.0000	100.00
43.5	1,541,327	181	0.0001	0.9999	100.00
44.5	1,511,015		0.0000	1.0000	99.99
45.5	1,479,425		0.0000	1.0000	99.99
46.5	1,456,979		0.0000	1.0000	99.99
47.5	1,436,422		0.0000	1.0000	99.99
48.5	1,401,841		0.0000	1.0000	99.99
49.5	1,375,393		0.0000	1.0000	99.99
50.5	1,135,470		0.0000	1.0000	99.99
51.5	1,197,625	9	0.0000	1.0000	99.99
52.5	1,129,540		0.0000	1.0000	99.99
53.5	1,099,573	189	0.0002	0.9998	99.99
54.5	1,022,617	2	0.0000	1.0000	99.97
55.5	941,942		0.0000	1.0000	99.97
56.5	893,575		0.0000	1.0000	99.97
57.5	861,044		0.0000	1.0000	99.97
58.5	822,232	3	0.0000	1.0000	99.97
59.5	767,158	2	0.0000	1.0000	99.97
60.5	719,579		0.0000	1.0000	99.97
61.5	639,709		0.0000	1.0000	99.97
62.5	629,790		0.0000	1.0000	99.97
63.5	576,928		0.0000	1.0000	99.97
64.5	500,173	94	0.0002	0.9998	99.97
65.5	482,910		0.0000	1.0000	99.95
66.5	463,382		0.0000	1.0000	99.95
67.5	418,057		0.0000	1.0000	99.95
68.5	386,263		0.0000	1.0000	99.95
69.5	127,639		0.0000	1.0000	99.95
70.5	127,639		0.0000	1.0000	99.95
71.5	127,639		0.0000	1.0000	99.95
72.5	127,639		0.0000	1.0000	99.95
73.5	127,639		0.0000	1.0000	99.95
74.5	127,639		0.0000	1.0000	99.95
75.5	127,639		0.0000	1.0000	99.95
76.5	127,639		0.0000	1.0000	99.95
77.5					99.95

THE POTOMAC EDISON COMPANY
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1950-2022 EXPERIENCE BAND 1997-2022

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	6,360,414		0.0000	1.0000	100.00
0.5	6,409,753		0.0000	1.0000	100.00
1.5	5,714,261		0.0000	1.0000	100.00
2.5	6,491,053		0.0000	1.0000	100.00
3.5	6,206,278		0.0000	1.0000	100.00
4.5	7,040,596		0.0000	1.0000	100.00
5.5	7,176,267		0.0000	1.0000	100.00
6.5	7,087,111		0.0000	1.0000	100.00
7.5	7,055,721	320	0.0000	1.0000	100.00
8.5	7,086,248		0.0000	1.0000	100.00
9.5	7,097,770		0.0000	1.0000	100.00
10.5	7,267,795		0.0000	1.0000	100.00
11.5	7,421,573	7,343	0.0010	0.9990	100.00
12.5	6,721,949		0.0000	1.0000	99.90
13.5	6,612,627		0.0000	1.0000	99.90
14.5	5,635,079		0.0000	1.0000	99.90
15.5	6,009,956		0.0000	1.0000	99.90
16.5	5,812,244		0.0000	1.0000	99.90
17.5	5,636,801		0.0000	1.0000	99.90
18.5	5,685,709		0.0000	1.0000	99.90
19.5	4,675,959	6,010	0.0013	0.9987	99.90
20.5	4,999,436		0.0000	1.0000	99.77
21.5	5,062,226	9,087	0.0018	0.9982	99.77
22.5	4,668,335	1,951	0.0004	0.9996	99.59
23.5	4,704,812	4,364	0.0009	0.9991	99.55
24.5	4,432,358		0.0000	1.0000	99.46
25.5	4,538,856	2,852	0.0006	0.9994	99.46
26.5	4,488,294		0.0000	1.0000	99.39
27.5	3,815,182	3,954	0.0010	0.9990	99.39
28.5	2,835,769		0.0000	1.0000	99.29
29.5	2,583,777		0.0000	1.0000	99.29
30.5	1,738,287	252	0.0001	0.9999	99.29
31.5	1,647,106	4,004	0.0024	0.9976	99.28
32.5	1,413,067	5,406	0.0038	0.9962	99.03
33.5	1,419,944		0.0000	1.0000	98.66
34.5	1,416,895	372	0.0003	0.9997	98.66
35.5	1,410,910	12,445	0.0088	0.9912	98.63
36.5	1,420,146	3,507	0.0025	0.9975	97.76
37.5	1,036,534		0.0000	1.0000	97.52
38.5	988,868		0.0000	1.0000	97.52

THE POTOMAC EDISON COMPANY

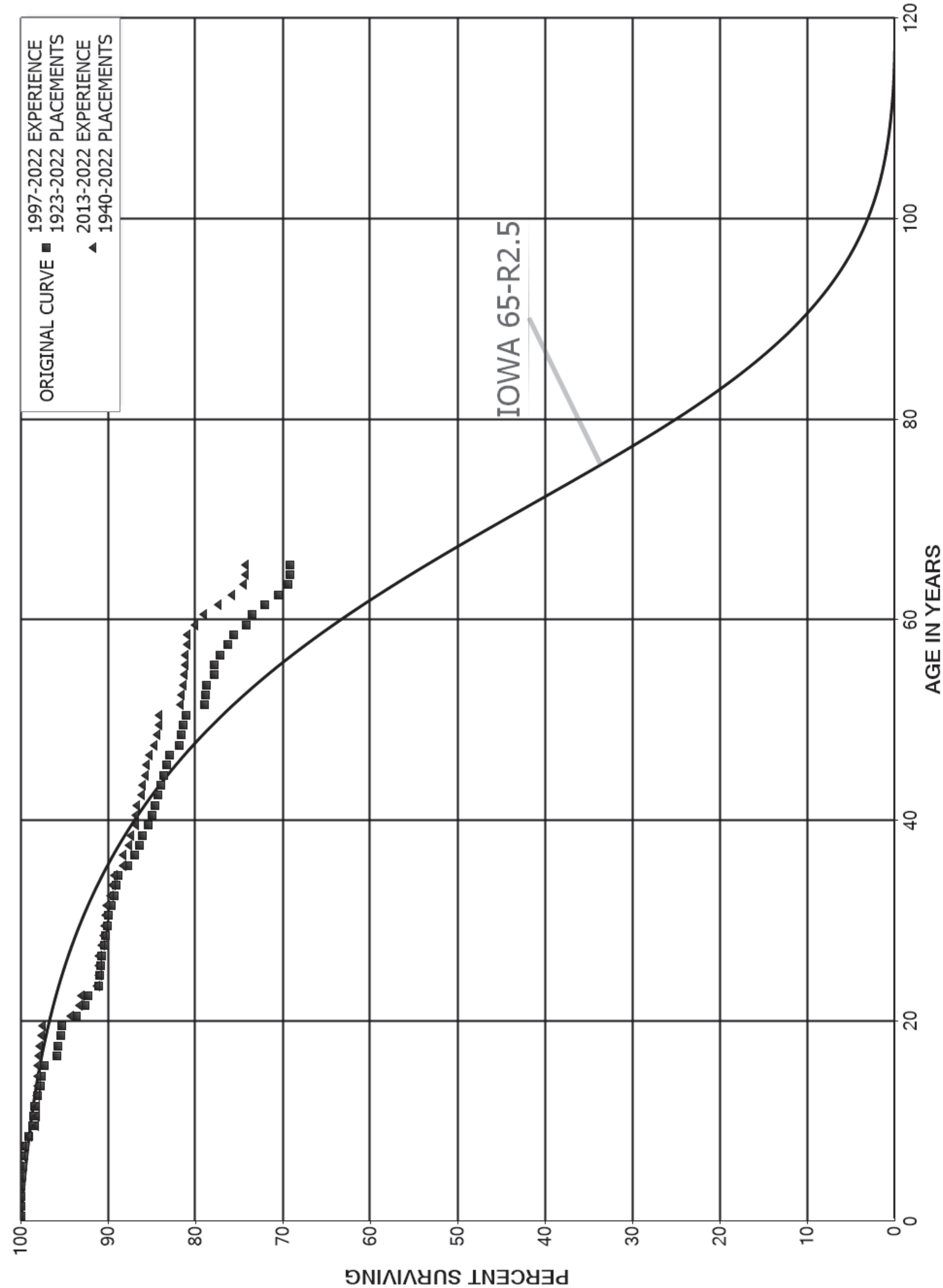
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1950-2022 EXPERIENCE BAND 1997-2022

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	1,014,186		0.0000	1.0000	97.52
40.5	995,264	1,064	0.0011	0.9989	97.52
41.5	827,137		0.0000	1.0000	97.41
42.5	764,333		0.0000	1.0000	97.41
43.5	769,671	233	0.0003	0.9997	97.41
44.5	711,483	5,217	0.0073	0.9927	97.38
45.5	604,563	89	0.0001	0.9999	96.67
46.5	521,137	2,002	0.0038	0.9962	96.66
47.5	394,455		0.0000	1.0000	96.28
48.5	400,278		0.0000	1.0000	96.28
49.5	403,269	2,306	0.0057	0.9943	96.28
50.5	401,976	6,598	0.0164	0.9836	95.73
51.5	333,799	210	0.0006	0.9994	94.16
52.5	226,256	333	0.0015	0.9985	94.10
53.5	223,455		0.0000	1.0000	93.96
54.5	160,963		0.0000	1.0000	93.96
55.5	146,731		0.0000	1.0000	93.96
56.5	127,921		0.0000	1.0000	93.96
57.5	127,678		0.0000	1.0000	93.96
58.5	116,198		0.0000	1.0000	93.96
59.5	112,666		0.0000	1.0000	93.96
60.5	114,868		0.0000	1.0000	93.96
61.5	68,715	51	0.0007	0.9993	93.96
62.5	113,096		0.0000	1.0000	93.89
63.5	106,940		0.0000	1.0000	93.89
64.5	101,780		0.0000	1.0000	93.89
65.5	22,286		0.0000	1.0000	93.89
66.5	21,791		0.0000	1.0000	93.89
67.5	19,183		0.0000	1.0000	93.89
68.5	17,609		0.0000	1.0000	93.89
69.5	10,486		0.0000	1.0000	93.89
70.5	2,284		0.0000	1.0000	93.89
71.5	2,284		0.0000	1.0000	93.89
72.5					93.89

THE POTOMAC EDISON COMPANY
ACCOUNT 362.00 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2022 EXPERIENCE BAND 1997-2022

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	134,678,801		0.0000	1.0000	100.00
0.5	129,808,863	43,498	0.0003	0.9997	100.00
1.5	126,055,818	47,371	0.0004	0.9996	99.97
2.5	126,063,463	26,670	0.0002	0.9998	99.93
3.5	120,184,565	25,838	0.0002	0.9998	99.91
4.5	120,373,354	181,489	0.0015	0.9985	99.89
5.5	117,667,581	177,128	0.0015	0.9985	99.74
6.5	112,064,551	103,795	0.0009	0.9991	99.59
7.5	116,747,853	462,248	0.0040	0.9960	99.49
8.5	115,274,937	526,921	0.0046	0.9954	99.10
9.5	110,894,557	103,018	0.0009	0.9991	98.65
10.5	110,102,723	150,229	0.0014	0.9986	98.55
11.5	112,315,574	442,591	0.0039	0.9961	98.42
12.5	110,495,529	291,850	0.0026	0.9974	98.03
13.5	105,181,411	204,087	0.0019	0.9981	97.77
14.5	85,269,286	299,985	0.0035	0.9965	97.58
15.5	81,750,907	1,146,789	0.0140	0.9860	97.24
16.5	78,820,368	133,647	0.0017	0.9983	95.88
17.5	73,217,634	215,373	0.0029	0.9971	95.71
18.5	66,696,691	113,593	0.0017	0.9983	95.43
19.5	65,967,297	1,177,864	0.0179	0.9821	95.27
20.5	65,516,038	694,734	0.0106	0.9894	93.57
21.5	63,343,256	225,176	0.0036	0.9964	92.58
22.5	58,483,110	731,708	0.0125	0.9875	92.25
23.5	57,820,165	124,553	0.0022	0.9978	91.09
24.5	54,538,065	49,206	0.0009	0.9991	90.90
25.5	54,681,262	85,533	0.0016	0.9984	90.82
26.5	53,223,085	166,947	0.0031	0.9969	90.67
27.5	48,187,879	83,834	0.0017	0.9983	90.39
28.5	40,431,032	75,498	0.0019	0.9981	90.23
29.5	38,697,669	72,980	0.0019	0.9981	90.06
30.5	35,590,942	89,433	0.0025	0.9975	89.89
31.5	31,925,550	135,128	0.0042	0.9958	89.67
32.5	28,593,707	73,084	0.0026	0.9974	89.29
33.5	23,850,047	55,130	0.0023	0.9977	89.06
34.5	22,554,664	287,793	0.0128	0.9872	88.85
35.5	21,871,515	184,352	0.0084	0.9916	87.72
36.5	21,525,007	145,897	0.0068	0.9932	86.98
37.5	18,478,980	68,155	0.0037	0.9963	86.39
38.5	17,128,207	131,917	0.0077	0.9923	86.07

THE POTOMAC EDISON COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2022 EXPERIENCE BAND 1997-2022

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	15,850,717	94,509	0.0060	0.9940	85.41
40.5	15,002,778	43,372	0.0029	0.9971	84.90
41.5	14,273,114	64,554	0.0045	0.9955	84.65
42.5	13,469,487	44,110	0.0033	0.9967	84.27
43.5	12,773,588	65,709	0.0051	0.9949	84.00
44.5	11,993,471	41,904	0.0035	0.9965	83.56
45.5	10,457,513	43,674	0.0042	0.9958	83.27
46.5	8,891,219	113,284	0.0127	0.9873	82.92
47.5	7,941,800	23,439	0.0030	0.9970	81.87
48.5	7,392,832	21,309	0.0029	0.9971	81.63
49.5	6,601,276	28,255	0.0043	0.9957	81.39
50.5	6,259,182	157,279	0.0251	0.9749	81.04
51.5	5,569,441	10,658	0.0019	0.9981	79.01
52.5	3,770,185	4,941	0.0013	0.9987	78.85
53.5	3,338,710	37,216	0.0111	0.9889	78.75
54.5	2,896,260	2,675	0.0009	0.9991	77.87
55.5	2,635,256	20,391	0.0077	0.9923	77.80
56.5	2,374,719	28,372	0.0119	0.9881	77.20
57.5	2,290,384	19,055	0.0083	0.9917	76.28
58.5	2,118,332	39,776	0.0188	0.9812	75.64
59.5	1,962,456	19,929	0.0102	0.9898	74.22
60.5	1,901,834	35,741	0.0188	0.9812	73.47
61.5	1,591,758	34,325	0.0216	0.9784	72.09
62.5	1,228,256	19,238	0.0157	0.9843	70.53
63.5	952,279	2,821	0.0030	0.9970	69.43
64.5	796,076		0.0000	1.0000	69.22
65.5	693,422	28,318	0.0408	0.9592	69.22
66.5	499,895	94	0.0002	0.9998	66.40
67.5	444,801		0.0000	1.0000	66.38
68.5	362,908		0.0000	1.0000	66.38
69.5	297,668		0.0000	1.0000	66.38
70.5	193,556		0.0000	1.0000	66.38
71.5	125,219		0.0000	1.0000	66.38
72.5	117,313		0.0000	1.0000	66.38
73.5	61,283		0.0000	1.0000	66.38
74.5	60,149		0.0000	1.0000	66.38
75.5	30,997		0.0000	1.0000	66.38
76.5	27,944		0.0000	1.0000	66.38
77.5	27,944		0.0000	1.0000	66.38
78.5	27,944		0.0000	1.0000	66.38

THE POTOMAC EDISON COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2022 EXPERIENCE BAND 1997-2022

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	22,193		0.0000	1.0000	66.38
80.5	22,193	4,766	0.2148	0.7852	66.38
81.5	17,427		0.0000	1.0000	52.13
82.5	7,786		0.0000	1.0000	52.13
83.5	7,786		0.0000	1.0000	52.13
84.5	7,786		0.0000	1.0000	52.13
85.5	7,786		0.0000	1.0000	52.13
86.5	7,786	7,786	1.0000		52.13
87.5					

THE POTOMAC EDISON COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1940-2022 EXPERIENCE BAND 2013-2022

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	60,520,898		0.0000	1.0000	100.00
0.5	52,287,940		0.0000	1.0000	100.00
1.5	45,189,432		0.0000	1.0000	100.00
2.5	38,825,786		0.0000	1.0000	100.00
3.5	36,915,375		0.0000	1.0000	100.00
4.5	55,333,254	1,803	0.0000	1.0000	100.00
5.5	53,145,252	139,982	0.0026	0.9974	100.00
6.5	46,325,057	52,140	0.0011	0.9989	99.73
7.5	53,152,769	387,250	0.0073	0.9927	99.62
8.5	58,303,817	431,155	0.0074	0.9926	98.90
9.5	55,775,669	63,674	0.0011	0.9989	98.16
10.5	55,602,992	12,929	0.0002	0.9998	98.05
11.5	57,451,490	10,591	0.0002	0.9998	98.03
12.5	59,463,833	7,281	0.0001	0.9999	98.01
13.5	53,750,240	29,730	0.0006	0.9994	98.00
14.5	36,660,060	12,723	0.0003	0.9997	97.94
15.5	33,425,297	19,198	0.0006	0.9994	97.91
16.5	34,104,224	49,872	0.0015	0.9985	97.85
17.5	33,577,840	83,525	0.0025	0.9975	97.71
18.5	34,343,003	7,349	0.0002	0.9998	97.47
19.5	33,929,022	1,138,604	0.0336	0.9664	97.45
20.5	35,148,380	353,811	0.0101	0.9899	94.18
21.5	35,768,684	85,529	0.0024	0.9976	93.23
22.5	34,591,985	683,571	0.0198	0.9802	93.01
23.5	37,883,177	85,713	0.0023	0.9977	91.17
24.5	35,501,875	3,040	0.0001	0.9999	90.96
25.5	35,765,749	16,270	0.0005	0.9995	90.95
26.5	32,810,926	106,753	0.0033	0.9967	90.91
27.5	30,788,216	74,273	0.0024	0.9976	90.62
28.5	24,431,845	27,712	0.0011	0.9989	90.40
29.5	23,829,993	27,313	0.0011	0.9989	90.30
30.5	21,585,937	25,329	0.0012	0.9988	90.19
31.5	18,627,790	101,192	0.0054	0.9946	90.09
32.5	15,795,668	41,470	0.0026	0.9974	89.60
33.5	11,684,105	24,926	0.0021	0.9979	89.36
34.5	11,295,917	126,888	0.0112	0.9888	89.17
35.5	12,574,731	791	0.0001	0.9999	88.17
36.5	13,677,209	94,089	0.0069	0.9931	88.16
37.5	11,371,388	32,679	0.0029	0.9971	87.56
38.5	10,439,279	68,980	0.0066	0.9934	87.31

THE POTOMAC EDISON COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-2022 EXPERIENCE BAND 2013-2022

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	9,847,495	4,312	0.0004	0.9996	86.73
40.5	9,147,050	12,055	0.0013	0.9987	86.69
41.5	8,913,145	49,384	0.0055	0.9945	86.58
42.5	9,765,619	12,073	0.0012	0.9988	86.10
43.5	9,478,500	46,148	0.0049	0.9951	85.99
44.5	8,967,722	8,596	0.0010	0.9990	85.57
45.5	7,595,533	27,887	0.0037	0.9963	85.49
46.5	6,284,222	39,699	0.0063	0.9937	85.18
47.5	5,381,640	21,215	0.0039	0.9961	84.64
48.5	5,112,681	14,661	0.0029	0.9971	84.30
49.5	4,427,957	155	0.0000	1.0000	84.06
50.5	4,147,276	118,190	0.0285	0.9715	84.06
51.5	3,829,427	8,776	0.0023	0.9977	81.66
52.5	2,361,712	4,002	0.0017	0.9983	81.48
53.5	2,203,701	5,178	0.0023	0.9977	81.34
54.5	1,986,305	1,640	0.0008	0.9992	81.15
55.5	1,848,996	767	0.0004	0.9996	81.08
56.5	1,787,066	3,527	0.0020	0.9980	81.05
57.5	1,771,533	2,188	0.0012	0.9988	80.89
58.5	1,684,088	18,435	0.0109	0.9891	80.79
59.5	1,618,081	18,819	0.0116	0.9884	79.90
60.5	1,662,866	35,741	0.0215	0.9785	78.97
61.5	1,463,681	29,137	0.0199	0.9801	77.28
62.5	1,113,804	19,238	0.0173	0.9827	75.74
63.5	901,642	2,821	0.0031	0.9969	74.43
64.5	745,439		0.0000	1.0000	74.20
65.5	671,938	25,278	0.0376	0.9624	74.20
66.5	479,736	94	0.0002	0.9998	71.41
67.5	424,643		0.0000	1.0000	71.39
68.5	342,749		0.0000	1.0000	71.39
69.5	283,261		0.0000	1.0000	71.39
70.5	179,148		0.0000	1.0000	71.39
71.5	109,677		0.0000	1.0000	71.39
72.5	111,412		0.0000	1.0000	71.39
73.5	47,597		0.0000	1.0000	71.39
74.5	47,597		0.0000	1.0000	71.39
75.5	18,445		0.0000	1.0000	71.39
76.5	15,392		0.0000	1.0000	71.39
77.5	15,392		0.0000	1.0000	71.39
78.5	15,392		0.0000	1.0000	71.39

THE POTOMAC EDISON COMPANY

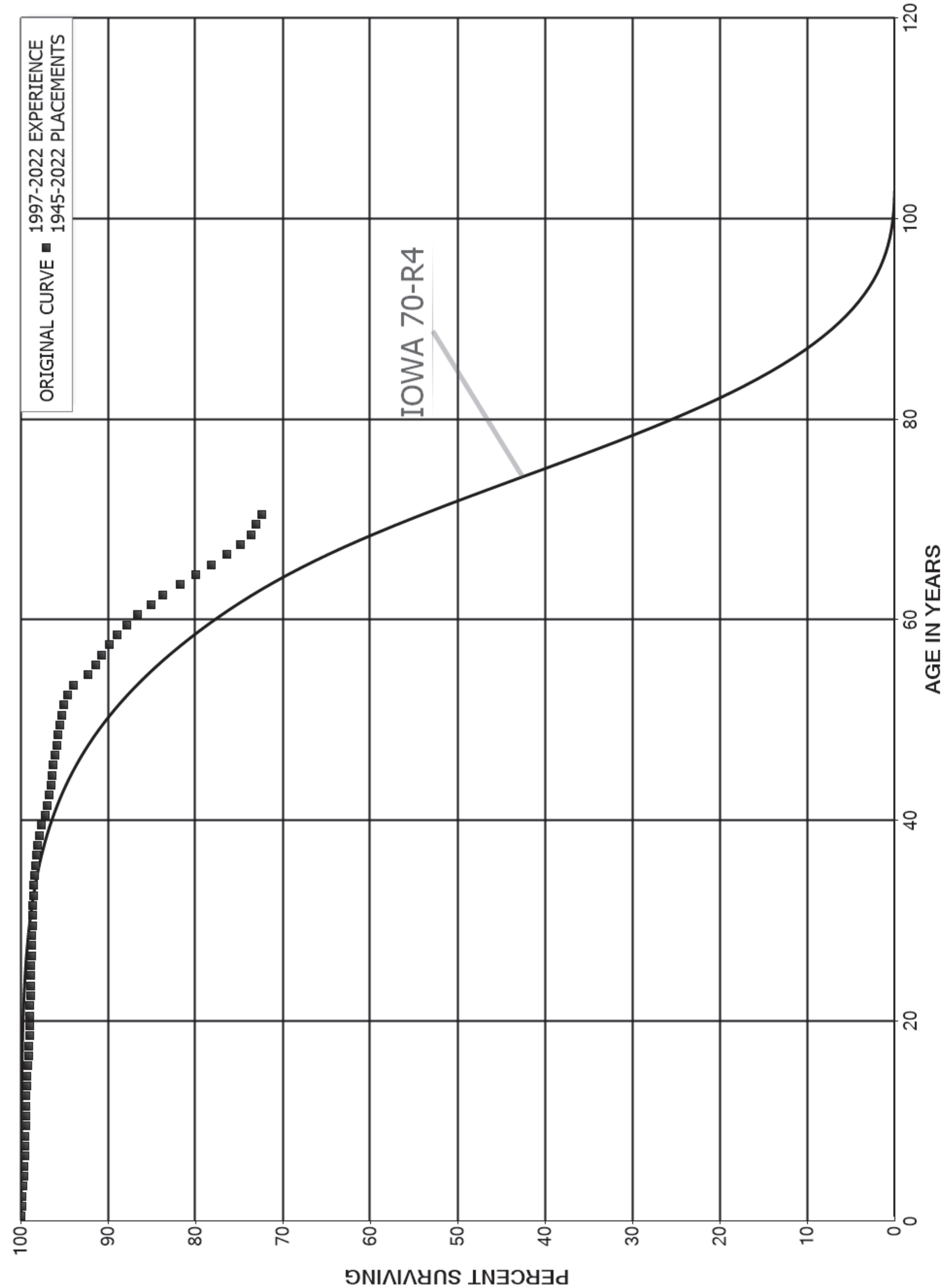
ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-2022 EXPERIENCE BAND 2013-2022

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	9,641		0.0000	1.0000	71.39
80.5	9,641		0.0000	1.0000	71.39
81.5	9,641		0.0000	1.0000	71.39
82.5					71.39

THE POTOMAC EDISON COMPANY
ACCOUNT 364.00 POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1997-2022

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	89,704,276	51,187	0.0006	0.9994	100.00
0.5	87,685,345	78,182	0.0009	0.9991	99.94
1.5	82,691,297	58,886	0.0007	0.9993	99.85
2.5	79,493,235	49,741	0.0006	0.9994	99.78
3.5	77,245,268	50,492	0.0007	0.9993	99.72
4.5	73,656,584	40,064	0.0005	0.9995	99.66
5.5	71,881,505	41,733	0.0006	0.9994	99.60
6.5	69,667,867	30,786	0.0004	0.9996	99.54
7.5	67,876,496	21,233	0.0003	0.9997	99.50
8.5	64,682,373	13,935	0.0002	0.9998	99.47
9.5	63,439,591	6,669	0.0001	0.9999	99.45
10.5	58,063,965	25,683	0.0004	0.9996	99.44
11.5	56,100,963	23,924	0.0004	0.9996	99.39
12.5	52,144,825	16,694	0.0003	0.9997	99.35
13.5	52,192,449	40,168	0.0008	0.9992	99.32
14.5	46,517,583	20,384	0.0004	0.9996	99.24
15.5	45,021,177	35,536	0.0008	0.9992	99.20
16.5	45,574,214	30,846	0.0007	0.9993	99.12
17.5	43,783,837	19,647	0.0004	0.9996	99.05
18.5	43,483,597	14,374	0.0003	0.9997	99.01
19.5	43,736,845	20,974	0.0005	0.9995	98.98
20.5	44,412,104	10,770	0.0002	0.9998	98.93
21.5	41,426,487	8,971	0.0002	0.9998	98.90
22.5	41,558,827	12,993	0.0003	0.9997	98.88
23.5	40,827,673	9,867	0.0002	0.9998	98.85
24.5	36,934,874	11,043	0.0003	0.9997	98.83
25.5	35,414,293	9,796	0.0003	0.9997	98.80
26.5	34,024,550	9,915	0.0003	0.9997	98.77
27.5	32,494,758	12,232	0.0004	0.9996	98.74
28.5	30,304,691	12,436	0.0004	0.9996	98.70
29.5	28,972,029	15,244	0.0005	0.9995	98.66
30.5	27,710,439	11,814	0.0004	0.9996	98.61
31.5	26,305,071	11,924	0.0005	0.9995	98.57
32.5	24,889,504	17,096	0.0007	0.9993	98.53
33.5	24,180,551	20,218	0.0008	0.9992	98.46
34.5	23,612,047	26,855	0.0011	0.9989	98.38
35.5	22,964,087	28,087	0.0012	0.9988	98.26
36.5	22,020,920	23,353	0.0011	0.9989	98.14
37.5	20,756,145	32,437	0.0016	0.9984	98.04
38.5	19,647,220	51,160	0.0026	0.9974	97.89

THE POTOMAC EDISON COMPANY

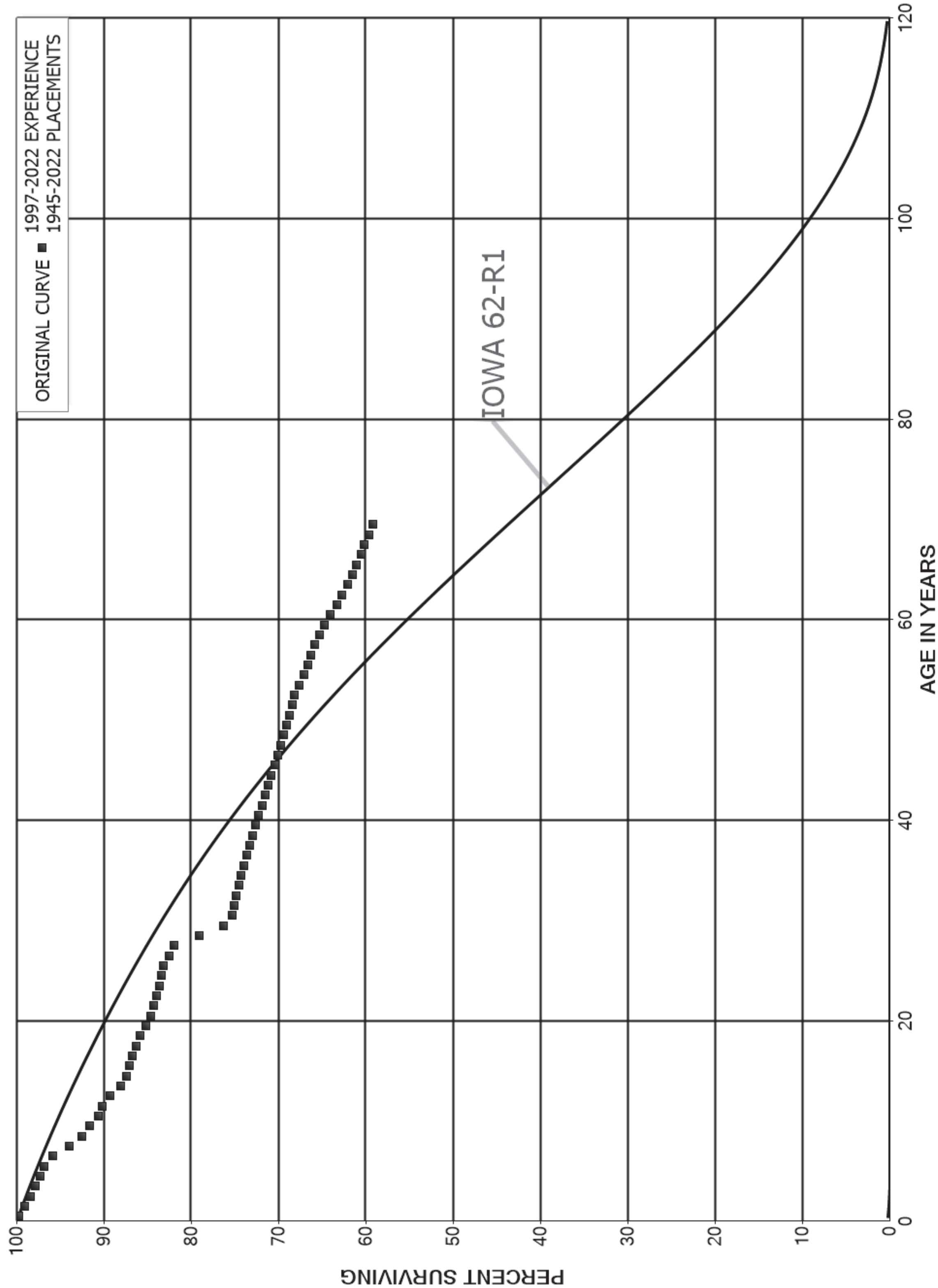
ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1997-2022

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	18,586,044	87,065	0.0047	0.9953	97.63
40.5	17,218,615	48,526	0.0028	0.9972	97.17
41.5	15,963,631	28,323	0.0018	0.9982	96.90
42.5	14,804,759	28,429	0.0019	0.9981	96.73
43.5	15,196,496	27,251	0.0018	0.9982	96.54
44.5	14,354,282	20,062	0.0014	0.9986	96.37
45.5	13,460,805	26,895	0.0020	0.9980	96.23
46.5	12,657,238	22,715	0.0018	0.9982	96.04
47.5	12,015,866	24,670	0.0021	0.9979	95.87
48.5	10,976,853	21,133	0.0019	0.9981	95.67
49.5	10,328,255	22,586	0.0022	0.9978	95.49
50.5	9,479,304	24,225	0.0026	0.9974	95.28
51.5	9,417,882	36,895	0.0039	0.9961	95.04
52.5	8,626,760	70,152	0.0081	0.9919	94.66
53.5	7,908,723	138,934	0.0176	0.9824	93.89
54.5	7,004,171	64,154	0.0092	0.9908	92.25
55.5	6,377,844	46,971	0.0074	0.9926	91.40
56.5	5,832,472	55,562	0.0095	0.9905	90.73
57.5	5,324,228	54,660	0.0103	0.9897	89.86
58.5	4,828,618	62,399	0.0129	0.9871	88.94
59.5	4,305,000	59,864	0.0139	0.9861	87.79
60.5	3,776,233	63,797	0.0169	0.9831	86.57
61.5	3,281,979	54,054	0.0165	0.9835	85.11
62.5	3,009,571	69,451	0.0231	0.9769	83.71
63.5	2,555,547	58,815	0.0230	0.9770	81.77
64.5	2,215,377	48,729	0.0220	0.9780	79.89
65.5	2,022,138	44,619	0.0221	0.9779	78.13
66.5	1,836,217	38,704	0.0211	0.9789	76.41
67.5	1,603,043	24,725	0.0154	0.9846	74.80
68.5	1,465,915	12,390	0.0085	0.9915	73.65
69.5	333,341	2,948	0.0088	0.9912	73.02
70.5	330,393	9,208	0.0279	0.9721	72.38
71.5	321,184	10,892	0.0339	0.9661	70.36
72.5	310,292	12,843	0.0414	0.9586	67.97
73.5	297,450	14,512	0.0488	0.9512	65.16
74.5	282,938	14,936	0.0528	0.9472	61.98
75.5	268,002	12,124	0.0452	0.9548	58.71
76.5	255,878	5,288	0.0207	0.9793	56.05
77.5					54.90

THE POTOMAC EDISON COMPANY
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1997-2022

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	120,782,030	377,052	0.0031	0.9969	100.00
0.5	118,916,739	755,061	0.0063	0.9937	99.69
1.5	114,096,154	732,977	0.0064	0.9936	99.05
2.5	107,283,809	592,397	0.0055	0.9945	98.42
3.5	99,600,759	599,400	0.0060	0.9940	97.88
4.5	92,747,225	462,281	0.0050	0.9950	97.29
5.5	88,272,438	909,146	0.0103	0.9897	96.80
6.5	82,439,705	1,597,944	0.0194	0.9806	95.80
7.5	78,211,530	1,202,609	0.0154	0.9846	93.95
8.5	71,152,403	714,194	0.0100	0.9900	92.50
9.5	68,037,844	699,688	0.0103	0.9897	91.57
10.5	54,816,586	305,168	0.0056	0.9944	90.63
11.5	51,783,436	504,761	0.0097	0.9903	90.13
12.5	48,304,989	626,205	0.0130	0.9870	89.25
13.5	47,547,653	361,587	0.0076	0.9924	88.09
14.5	45,200,660	196,669	0.0044	0.9956	87.42
15.5	44,259,715	162,387	0.0037	0.9963	87.04
16.5	44,399,402	239,495	0.0054	0.9946	86.72
17.5	41,714,325	211,845	0.0051	0.9949	86.25
18.5	41,243,384	326,041	0.0079	0.9921	85.82
19.5	41,304,313	271,417	0.0066	0.9934	85.14
20.5	41,958,392	154,148	0.0037	0.9963	84.58
21.5	39,350,922	169,968	0.0043	0.9957	84.27
22.5	39,326,145	144,522	0.0037	0.9963	83.90
23.5	38,948,502	86,683	0.0022	0.9978	83.60
24.5	33,902,887	83,947	0.0025	0.9975	83.41
25.5	31,713,633	285,976	0.0090	0.9910	83.20
26.5	30,352,608	173,274	0.0057	0.9943	82.45
27.5	28,289,105	1,020,153	0.0361	0.9639	81.98
28.5	24,865,249	846,469	0.0340	0.9660	79.03
29.5	22,587,074	307,272	0.0136	0.9864	76.34
30.5	20,731,277	56,372	0.0027	0.9973	75.30
31.5	19,961,791	65,074	0.0033	0.9967	75.09
32.5	19,011,945	73,138	0.0038	0.9962	74.85
33.5	18,712,053	73,078	0.0039	0.9961	74.56
34.5	18,575,810	67,310	0.0036	0.9964	74.27
35.5	18,349,183	86,709	0.0047	0.9953	74.00
36.5	17,587,695	86,758	0.0049	0.9951	73.65
37.5	16,702,157	78,443	0.0047	0.9953	73.29
38.5	16,287,258	73,885	0.0045	0.9955	72.94

THE POTOMAC EDISON COMPANY

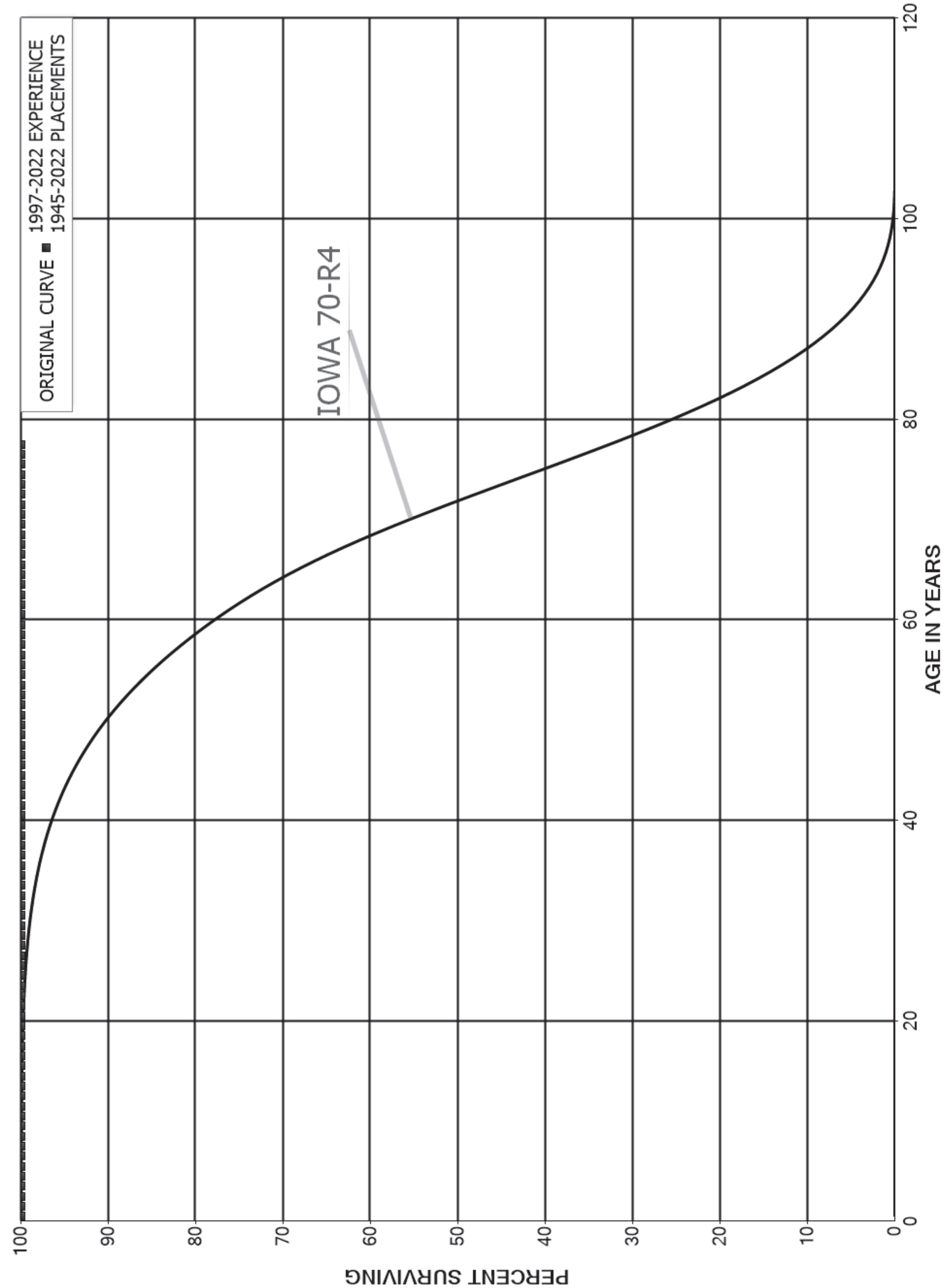
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1997-2022

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	15,649,936	74,151	0.0047	0.9953	72.61
40.5	14,500,861	76,380	0.0053	0.9947	72.27
41.5	13,315,028	64,924	0.0049	0.9951	71.89
42.5	12,127,385	60,410	0.0050	0.9950	71.54
43.5	12,299,072	59,853	0.0049	0.9951	71.18
44.5	11,548,875	63,385	0.0055	0.9945	70.83
45.5	10,585,455	56,405	0.0053	0.9947	70.44
46.5	9,566,956	43,706	0.0046	0.9954	70.07
47.5	9,548,413	47,913	0.0050	0.9950	69.75
48.5	8,980,627	38,740	0.0043	0.9957	69.40
49.5	8,596,676	41,536	0.0048	0.9952	69.10
50.5	7,913,792	37,252	0.0047	0.9953	68.77
51.5	8,381,428	35,812	0.0043	0.9957	68.44
52.5	7,704,131	59,996	0.0078	0.9922	68.15
53.5	7,058,364	61,200	0.0087	0.9913	67.62
54.5	6,138,835	38,303	0.0062	0.9938	67.03
55.5	5,581,196	31,812	0.0057	0.9943	66.61
56.5	5,090,291	34,864	0.0068	0.9932	66.23
57.5	4,656,227	39,009	0.0084	0.9916	65.78
58.5	4,247,784	35,378	0.0083	0.9917	65.23
59.5	3,849,043	39,563	0.0103	0.9897	64.69
60.5	3,377,993	36,962	0.0109	0.9891	64.02
61.5	2,940,666	27,366	0.0093	0.9907	63.32
62.5	2,732,715	26,932	0.0099	0.9901	62.73
63.5	2,395,586	21,656	0.0090	0.9910	62.11
64.5	2,164,706	18,914	0.0087	0.9913	61.55
65.5	2,033,399	16,206	0.0080	0.9920	61.01
66.5	1,893,547	12,564	0.0066	0.9934	60.53
67.5	1,728,761	15,560	0.0090	0.9910	60.13
68.5	1,602,010	10,641	0.0066	0.9934	59.59
69.5	695,970	6,414	0.0092	0.9908	59.19
70.5	689,556	6,547	0.0095	0.9905	58.64
71.5	683,009	5,263	0.0077	0.9923	58.09
72.5	677,746	6,959	0.0103	0.9897	57.64
73.5	670,786	7,286	0.0109	0.9891	57.05
74.5	663,500	8,748	0.0132	0.9868	56.43
75.5	654,753	6,681	0.0102	0.9898	55.68
76.5	648,071	3,592	0.0055	0.9945	55.12
77.5					54.81

THE POTOMAC EDISON COMPANY
ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1997-2022

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	73,463,323		0.0000	1.0000	100.00
0.5	73,744,099		0.0000	1.0000	100.00
1.5	69,864,881		0.0000	1.0000	100.00
2.5	66,218,314		0.0000	1.0000	100.00
3.5	62,492,716		0.0000	1.0000	100.00
4.5	54,430,966		0.0000	1.0000	100.00
5.5	52,250,172		0.0000	1.0000	100.00
6.5	42,767,414		0.0000	1.0000	100.00
7.5	33,275,151		0.0000	1.0000	100.00
8.5	30,626,785		0.0000	1.0000	100.00
9.5	7,510,388		0.0000	1.0000	100.00
10.5	7,560,012		0.0000	1.0000	100.00
11.5	4,076,351		0.0000	1.0000	100.00
12.5	4,134,720		0.0000	1.0000	100.00
13.5	4,176,526		0.0000	1.0000	100.00
14.5	4,268,390		0.0000	1.0000	100.00
15.5	4,285,567		0.0000	1.0000	100.00
16.5	4,257,220		0.0000	1.0000	100.00
17.5	3,326,447		0.0000	1.0000	100.00
18.5	3,255,782		0.0000	1.0000	100.00
19.5	3,259,662		0.0000	1.0000	100.00
20.5	3,279,608		0.0000	1.0000	100.00
21.5	3,047,251		0.0000	1.0000	100.00
22.5	3,082,253		0.0000	1.0000	100.00
23.5	3,067,552		0.0000	1.0000	100.00
24.5	2,691,176		0.0000	1.0000	100.00
25.5	2,774,009		0.0000	1.0000	100.00
26.5	2,619,733		0.0000	1.0000	100.00
27.5	2,387,394		0.0000	1.0000	100.00
28.5	2,258,859		0.0000	1.0000	100.00
29.5	2,037,412		0.0000	1.0000	100.00
30.5	1,946,941		0.0000	1.0000	100.00
31.5	1,782,816		0.0000	1.0000	100.00
32.5	1,688,925		0.0000	1.0000	100.00
33.5	1,695,066		0.0000	1.0000	100.00
34.5	1,685,221		0.0000	1.0000	100.00
35.5	1,691,376		0.0000	1.0000	100.00
36.5	1,675,320		0.0000	1.0000	100.00
37.5	1,644,041		0.0000	1.0000	100.00
38.5	1,649,179		0.0000	1.0000	100.00

THE POTOMAC EDISON COMPANY

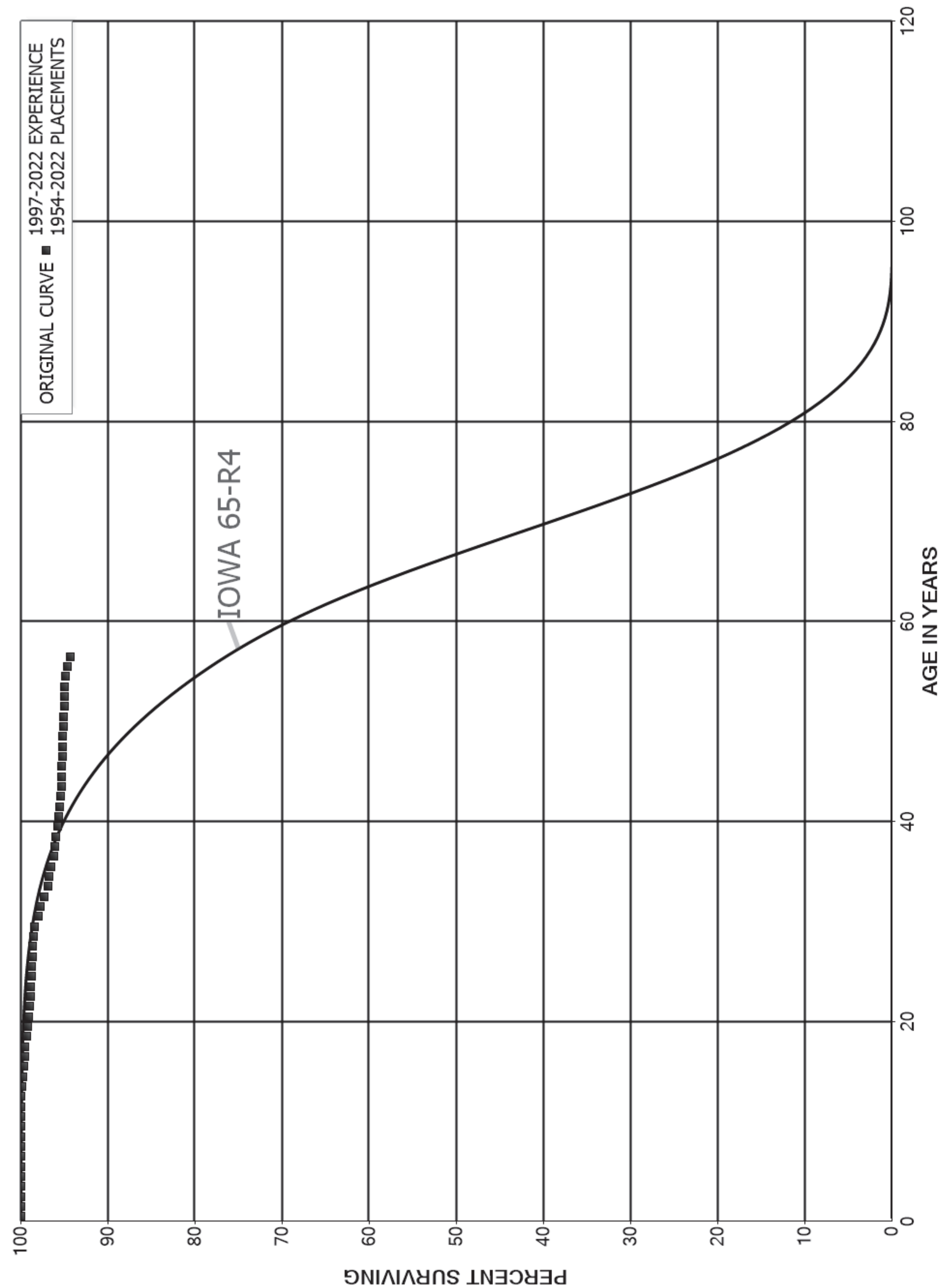
ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1997-2022

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	1,633,264		0.0000	1.0000	100.00
40.5	1,558,911		0.0000	1.0000	100.00
41.5	1,591,442		0.0000	1.0000	100.00
42.5	1,591,940		0.0000	1.0000	100.00
43.5	1,815,913		0.0000	1.0000	100.00
44.5	1,771,385		0.0000	1.0000	100.00
45.5	1,754,468		0.0000	1.0000	100.00
46.5	1,728,345		0.0000	1.0000	100.00
47.5	1,691,402		0.0000	1.0000	100.00
48.5	1,629,858		0.0000	1.0000	100.00
49.5	1,579,927		0.0000	1.0000	100.00
50.5	1,444,564		0.0000	1.0000	100.00
51.5	1,482,821		0.0000	1.0000	100.00
52.5	1,425,969		0.0000	1.0000	100.00
53.5	1,321,424		0.0000	1.0000	100.00
54.5	1,202,488		0.0000	1.0000	100.00
55.5	1,130,300		0.0000	1.0000	100.00
56.5	1,051,210		0.0000	1.0000	100.00
57.5	992,905		0.0000	1.0000	100.00
58.5	941,278		0.0000	1.0000	100.00
59.5	877,664		0.0000	1.0000	100.00
60.5	811,201		0.0000	1.0000	100.00
61.5	748,694		0.0000	1.0000	100.00
62.5	713,127		0.0000	1.0000	100.00
63.5	644,456		0.0000	1.0000	100.00
64.5	580,950		0.0000	1.0000	100.00
65.5	549,452		0.0000	1.0000	100.00
66.5	531,940		0.0000	1.0000	100.00
67.5	482,232		0.0000	1.0000	100.00
68.5	455,714		0.0000	1.0000	100.00
69.5	198,446		0.0000	1.0000	100.00
70.5	198,446		0.0000	1.0000	100.00
71.5	198,446		0.0000	1.0000	100.00
72.5	198,446		0.0000	1.0000	100.00
73.5	198,446		0.0000	1.0000	100.00
74.5	198,446		0.0000	1.0000	100.00
75.5	198,446		0.0000	1.0000	100.00
76.5	198,446		0.0000	1.0000	100.00
77.5					100.00

THE POTOMAC EDISON COMPANY
ACCOUNT 366.00 UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2022 EXPERIENCE BAND 1997-2022

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	48,679,625		0.0000	1.0000	100.00
0.5	50,028,161	3,600	0.0001	0.9999	100.00
1.5	50,332,816	24,173	0.0005	0.9995	99.99
2.5	50,040,249	5,741	0.0001	0.9999	99.94
3.5	48,909,199	667	0.0000	1.0000	99.93
4.5	48,897,457	2,192	0.0000	1.0000	99.93
5.5	48,728,881	26	0.0000	1.0000	99.93
6.5	48,952,520	11	0.0000	1.0000	99.93
7.5	49,168,499	318	0.0000	1.0000	99.93
8.5	49,554,580	663	0.0000	1.0000	99.93
9.5	49,212,601	421	0.0000	1.0000	99.93
10.5	49,234,883	2,749	0.0001	0.9999	99.92
11.5	48,146,103	3,734	0.0001	0.9999	99.92
12.5	47,360,033	50,414	0.0011	0.9989	99.91
13.5	47,364,448	17,096	0.0004	0.9996	99.80
14.5	44,557,742	51,816	0.0012	0.9988	99.77
15.5	42,434,552	49,813	0.0012	0.9988	99.65
16.5	41,951,233	35,240	0.0008	0.9992	99.54
17.5	39,665,276	50,350	0.0013	0.9987	99.45
18.5	37,731,473	38,111	0.0010	0.9990	99.33
19.5	37,733,664	61,094	0.0016	0.9984	99.23
20.5	37,757,737	28,907	0.0008	0.9992	99.07
21.5	31,941,016	49,244	0.0015	0.9985	98.99
22.5	29,860,422	14,258	0.0005	0.9995	98.84
23.5	29,843,797	9,548	0.0003	0.9997	98.79
24.5	24,807,607	11,842	0.0005	0.9995	98.76
25.5	21,371,227	11,794	0.0006	0.9994	98.71
26.5	19,683,403	9,903	0.0005	0.9995	98.66
27.5	17,221,866	10,945	0.0006	0.9994	98.61
28.5	15,403,747	19,282	0.0013	0.9987	98.54
29.5	13,911,460	66,148	0.0048	0.9952	98.42
30.5	12,575,644	33,379	0.0027	0.9973	97.95
31.5	11,418,417	41,526	0.0036	0.9964	97.69
32.5	10,073,499	49,516	0.0049	0.9951	97.34
33.5	8,919,775	9,740	0.0011	0.9989	96.86
34.5	7,882,864	17,672	0.0022	0.9978	96.75
35.5	7,061,521	23,168	0.0033	0.9967	96.54
36.5	6,154,881	10,528	0.0017	0.9983	96.22
37.5	5,323,156	6,297	0.0012	0.9988	96.05
38.5	4,940,696	10,698	0.0022	0.9978	95.94

THE POTOMAC EDISON COMPANY

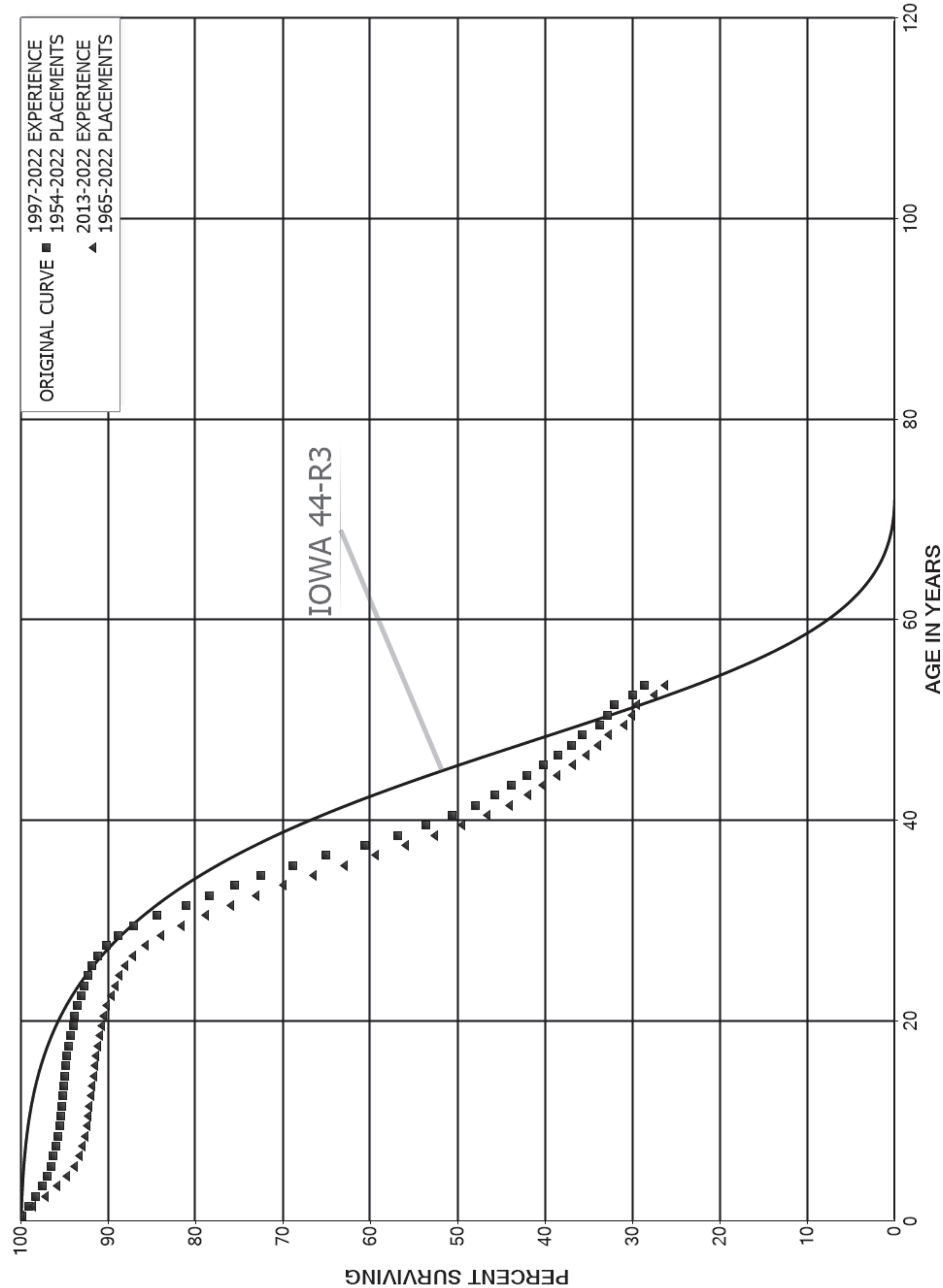
ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2022 EXPERIENCE BAND 1997-2022

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	4,483,086	7,105	0.0016	0.9984	95.73
40.5	4,127,815	4,654	0.0011	0.9989	95.58
41.5	3,752,394	1,253	0.0003	0.9997	95.47
42.5	3,164,924	5,123	0.0016	0.9984	95.44
43.5	2,620,986	624	0.0002	0.9998	95.29
44.5	2,083,418	369	0.0002	0.9998	95.26
45.5	1,678,832	601	0.0004	0.9996	95.25
46.5	1,198,942	340	0.0003	0.9997	95.21
47.5	948,930	495	0.0005	0.9995	95.19
48.5	619,006	419	0.0007	0.9993	95.14
49.5	299,242	131	0.0004	0.9996	95.07
50.5	192,751	82	0.0004	0.9996	95.03
51.5	162,033	64	0.0004	0.9996	94.99
52.5	136,633	58	0.0004	0.9996	94.95
53.5	96,895	110	0.0011	0.9989	94.91
54.5	71,999	133	0.0018	0.9982	94.81
55.5	47,668	174	0.0037	0.9963	94.63
56.5	4,508		0.0000	1.0000	94.28
57.5	1,066		0.0000	1.0000	94.28
58.5					94.28

THE POTOMAC EDISON COMPANY
ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2022 EXPERIENCE BAND 1997-2022

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	252,092,588	407,512	0.0016	0.9984	100.00
0.5	252,365,753	1,939,728	0.0077	0.9923	99.84
1.5	234,689,058	1,931,038	0.0082	0.9918	99.07
2.5	217,735,162	1,556,698	0.0071	0.9929	98.26
3.5	200,061,915	1,212,197	0.0061	0.9939	97.55
4.5	187,931,506	816,488	0.0043	0.9957	96.96
5.5	181,507,906	577,008	0.0032	0.9968	96.54
6.5	175,258,036	475,250	0.0027	0.9973	96.23
7.5	167,470,438	435,637	0.0026	0.9974	95.97
8.5	162,259,046	294,464	0.0018	0.9982	95.72
9.5	154,633,522	303,528	0.0020	0.9980	95.55
10.5	148,946,174	130,865	0.0009	0.9991	95.36
11.5	143,257,681	158,843	0.0011	0.9989	95.28
12.5	137,924,156	144,693	0.0010	0.9990	95.17
13.5	135,985,454	168,251	0.0012	0.9988	95.07
14.5	129,349,758	144,107	0.0011	0.9989	94.96
15.5	117,979,617	128,858	0.0011	0.9989	94.85
16.5	117,199,043	311,655	0.0027	0.9973	94.75
17.5	114,791,779	267,020	0.0023	0.9977	94.49
18.5	115,254,642	333,655	0.0029	0.9971	94.27
19.5	115,738,370	200,851	0.0017	0.9983	94.00
20.5	116,406,921	454,657	0.0039	0.9961	93.84
21.5	104,105,861	455,729	0.0044	0.9956	93.47
22.5	102,105,926	423,323	0.0041	0.9959	93.06
23.5	101,234,728	472,971	0.0047	0.9953	92.68
24.5	82,031,924	371,047	0.0045	0.9955	92.24
25.5	72,447,675	497,238	0.0069	0.9931	91.83
26.5	64,573,383	697,376	0.0108	0.9892	91.20
27.5	58,374,909	871,154	0.0149	0.9851	90.21
28.5	52,062,427	1,060,766	0.0204	0.9796	88.86
29.5	46,073,938	1,398,975	0.0304	0.9696	87.05
30.5	40,613,259	1,602,991	0.0395	0.9605	84.41
31.5	34,174,226	1,152,603	0.0337	0.9663	81.08
32.5	28,681,532	1,023,583	0.0357	0.9643	78.34
33.5	24,449,910	997,097	0.0408	0.9592	75.55
34.5	20,101,754	1,010,530	0.0503	0.9497	72.47
35.5	17,903,658	985,942	0.0551	0.9449	68.82
36.5	15,217,820	1,027,714	0.0675	0.9325	65.03
37.5	12,660,570	786,073	0.0621	0.9379	60.64
38.5	10,952,188	618,187	0.0564	0.9436	56.88

THE POTOMAC EDISON COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2022 EXPERIENCE BAND 1997-2022

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	9,270,838	531,775	0.0574	0.9426	53.67
40.5	7,936,214	418,868	0.0528	0.9472	50.59
41.5	6,544,307	304,949	0.0466	0.9534	47.92
42.5	5,341,145	213,817	0.0400	0.9600	45.69
43.5	4,198,582	166,649	0.0397	0.9603	43.86
44.5	3,124,727	147,748	0.0473	0.9527	42.12
45.5	2,177,402	90,319	0.0415	0.9585	40.12
46.5	1,541,405	58,426	0.0379	0.9621	38.46
47.5	964,871	33,686	0.0349	0.9651	37.00
48.5	464,405	25,141	0.0541	0.9459	35.71
49.5	374,664	10,677	0.0285	0.9715	33.78
50.5	292,846	6,316	0.0216	0.9784	32.81
51.5	191,024	12,661	0.0663	0.9337	32.11
52.5	102,756	4,734	0.0461	0.9539	29.98
53.5	49,653	1,214	0.0245	0.9755	28.60
54.5	16,805	292	0.0174	0.9826	27.90
55.5	9,177		0.0000	1.0000	27.41
56.5					27.41

THE POTOMAC EDISON COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2022 EXPERIENCE BAND 2013-2022

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	145,151,001	304,260	0.0021	0.9979	100.00
0.5	146,616,301	1,921,845	0.0131	0.9869	99.79
1.5	132,240,740	1,917,190	0.0145	0.9855	98.48
2.5	116,335,116	1,547,020	0.0133	0.9867	97.05
3.5	97,186,876	1,198,882	0.0123	0.9877	95.76
4.5	89,465,823	792,573	0.0089	0.9911	94.58
5.5	91,116,980	559,435	0.0061	0.9939	93.74
6.5	82,844,445	323,711	0.0039	0.9961	93.17
7.5	75,850,356	279,787	0.0037	0.9963	92.81
8.5	68,394,248	140,841	0.0021	0.9979	92.46
9.5	59,541,796	71,784	0.0012	0.9988	92.27
10.5	51,440,632	41,340	0.0008	0.9992	92.16
11.5	55,902,674	137,321	0.0025	0.9975	92.09
12.5	51,993,145	90,171	0.0017	0.9983	91.86
13.5	49,755,583	88,898	0.0018	0.9982	91.70
14.5	60,915,110	104,583	0.0017	0.9983	91.54
15.5	57,529,067	59,355	0.0010	0.9990	91.38
16.5	62,843,746	127,488	0.0020	0.9980	91.29
17.5	64,566,162	201,268	0.0031	0.9969	91.10
18.5	68,900,047	163,958	0.0024	0.9976	90.82
19.5	73,159,792	135,035	0.0018	0.9982	90.60
20.5	76,937,568	342,619	0.0045	0.9955	90.43
21.5	68,798,471	386,170	0.0056	0.9944	90.03
22.5	70,039,304	325,881	0.0047	0.9953	89.53
23.5	71,599,642	432,737	0.0060	0.9940	89.11
24.5	55,476,899	364,675	0.0066	0.9934	88.57
25.5	47,558,974	494,132	0.0104	0.9896	87.99
26.5	42,342,043	693,622	0.0164	0.9836	87.07
27.5	38,659,868	836,627	0.0216	0.9784	85.65
28.5	33,906,232	924,945	0.0273	0.9727	83.79
29.5	29,904,279	1,038,728	0.0347	0.9653	81.51
30.5	26,190,824	946,940	0.0362	0.9638	78.68
31.5	22,160,033	840,215	0.0379	0.9621	75.83
32.5	18,612,838	782,814	0.0421	0.9579	72.96
33.5	16,339,669	813,100	0.0498	0.9502	69.89
34.5	13,894,158	749,343	0.0539	0.9461	66.41
35.5	13,487,559	753,387	0.0559	0.9441	62.83
36.5	12,099,460	702,447	0.0581	0.9419	59.32
37.5	10,903,648	663,115	0.0608	0.9392	55.88
38.5	10,267,287	597,957	0.0582	0.9418	52.48

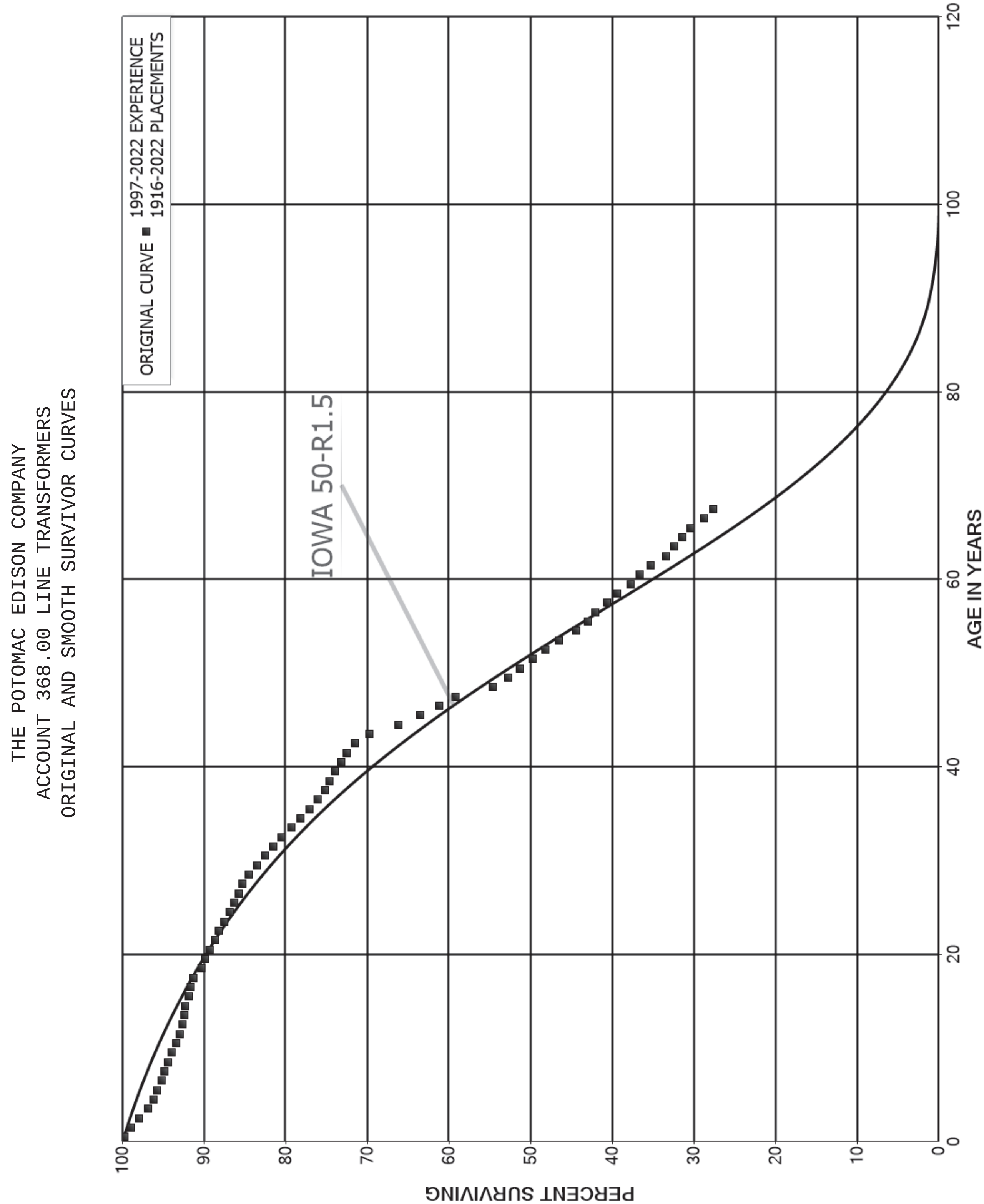
THE POTOMAC EDISON COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2022 EXPERIENCE BAND 2013-2022

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	8,731,144	523,614	0.0600	0.9400	49.42
40.5	7,499,926	410,990	0.0548	0.9452	46.46
41.5	6,253,493	292,991	0.0469	0.9531	43.91
42.5	5,167,993	211,465	0.0409	0.9591	41.85
43.5	4,098,156	165,811	0.0405	0.9595	40.14
44.5	3,076,340	147,128	0.0478	0.9522	38.52
45.5	2,142,816	89,899	0.0420	0.9580	36.68
46.5	1,534,637	57,699	0.0376	0.9624	35.14
47.5	964,871	33,686	0.0349	0.9651	33.82
48.5	464,405	25,141	0.0541	0.9459	32.64
49.5	374,664	10,677	0.0285	0.9715	30.87
50.5	292,846	6,316	0.0216	0.9784	29.99
51.5	191,024	12,661	0.0663	0.9337	29.34
52.5	102,756	4,734	0.0461	0.9539	27.40
53.5	49,653	1,214	0.0245	0.9755	26.13
54.5	16,805	292	0.0174	0.9826	25.50
55.5	9,177		0.0000	1.0000	25.05
56.5					25.05


THE POTOMAC EDISON COMPANY
ACCOUNT 368.00 LINE TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1997-2022 EXPERIENCE
1916-2022 PLACEMENTS
IOWA 50-R1.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120

THE POTOMAC EDISON COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1916-2022 EXPERIENCE BAND 1997-2022

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	141,703,819	455,198	0.0032	0.9968	100.00
0.5	137,568,696	1,058,703	0.0077	0.9923	99.68
1.5	152,451,056	1,465,155	0.0096	0.9904	98.91
2.5	147,305,769	1,663,739	0.0113	0.9887	97.96
3.5	141,646,880	1,017,967	0.0072	0.9928	96.85
4.5	135,533,276	564,624	0.0042	0.9958	96.16
5.5	132,945,225	767,626	0.0058	0.9942	95.76
6.5	131,940,243	540,159	0.0041	0.9959	95.21
7.5	132,514,368	638,079	0.0048	0.9952	94.82
8.5	132,739,029	632,174	0.0048	0.9952	94.36
9.5	132,340,361	777,389	0.0059	0.9941	93.91
10.5	128,846,745	506,249	0.0039	0.9961	93.36
11.5	120,134,080	452,710	0.0038	0.9962	92.99
12.5	114,157,860	266,843	0.0023	0.9977	92.64
13.5	113,038,778	199,611	0.0018	0.9982	92.42
14.5	105,857,502	451,112	0.0043	0.9957	92.26
15.5	101,705,815	292,281	0.0029	0.9971	91.87
16.5	102,129,567	401,474	0.0039	0.9961	91.60
17.5	101,516,709	1,038,603	0.0102	0.9898	91.24
18.5	101,380,424	587,975	0.0058	0.9942	90.31
19.5	102,465,443	561,042	0.0055	0.9945	89.79
20.5	102,892,442	738,395	0.0072	0.9928	89.29
21.5	93,417,889	506,752	0.0054	0.9946	88.65
22.5	92,417,580	643,459	0.0070	0.9930	88.17
23.5	92,490,311	710,327	0.0077	0.9923	87.56
24.5	83,395,328	555,749	0.0067	0.9933	86.89
25.5	83,473,645	526,838	0.0063	0.9937	86.31
26.5	83,402,148	503,153	0.0060	0.9940	85.76
27.5	63,429,686	542,412	0.0086	0.9914	85.25
28.5	59,405,315	683,364	0.0115	0.9885	84.52
29.5	55,509,607	724,574	0.0131	0.9869	83.54
30.5	52,708,770	589,123	0.0112	0.9888	82.45
31.5	49,634,405	649,661	0.0131	0.9869	81.53
32.5	45,154,173	687,303	0.0152	0.9848	80.46
33.5	38,963,693	525,812	0.0135	0.9865	79.24
34.5	33,857,995	463,404	0.0137	0.9863	78.17
35.5	29,698,102	408,322	0.0137	0.9863	77.10
36.5	26,181,601	279,558	0.0107	0.9893	76.04
37.5	23,778,486	205,691	0.0087	0.9913	75.23
38.5	21,325,385	178,052	0.0083	0.9917	74.58

THE POTOMAC EDISON COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1916-2022 EXPERIENCE BAND 1997-2022

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	19,601,375	209,569	0.0107	0.9893	73.96
40.5	17,588,872	159,795	0.0091	0.9909	73.16
41.5	15,742,098	220,351	0.0140	0.9860	72.50
42.5	14,303,151	361,679	0.0253	0.9747	71.49
43.5	12,762,389	636,274	0.0499	0.9501	69.68
44.5	10,482,056	419,111	0.0400	0.9600	66.20
45.5	8,726,945	328,066	0.0376	0.9624	63.56
46.5	7,606,652	249,617	0.0328	0.9672	61.17
47.5	6,690,920	516,149	0.0771	0.9229	59.16
48.5	5,458,484	182,165	0.0334	0.9666	54.60
49.5	4,796,568	134,055	0.0279	0.9721	52.77
50.5	4,302,810	128,996	0.0300	0.9700	51.30
51.5	3,716,919	121,877	0.0328	0.9672	49.76
52.5	3,098,201	107,676	0.0348	0.9652	48.13
53.5	2,322,112	102,047	0.0439	0.9561	46.46
54.5	1,664,124	52,789	0.0317	0.9683	44.42
55.5	1,300,808	28,063	0.0216	0.9784	43.01
56.5	921,033	31,476	0.0342	0.9658	42.08
57.5	701,650	21,662	0.0309	0.9691	40.64
58.5	582,977	24,597	0.0422	0.9578	39.39
59.5	497,919	14,212	0.0285	0.9715	37.72
60.5	453,255	17,141	0.0378	0.9622	36.65
61.5	384,534	20,267	0.0527	0.9473	35.26
62.5	331,054	10,375	0.0313	0.9687	33.40
63.5	281,558	8,680	0.0308	0.9692	32.36
64.5	231,295	7,323	0.0317	0.9683	31.36
65.5	181,362	9,865	0.0544	0.9456	30.37
66.5	120,161	4,730	0.0394	0.9606	28.71
67.5	94,627	2,949	0.0312	0.9688	27.58
68.5	80,962	413	0.0051	0.9949	26.72
69.5	22,140	1,127	0.0509	0.9491	26.59
70.5	13,215	3,888	0.2942	0.7058	25.23
71.5	5,968	555	0.0931	0.9069	17.81
72.5	4,923	922	0.1873	0.8127	16.15
73.5	4,174	6	0.0015	0.9985	13.13
74.5	3,831	218	0.0568	0.9432	13.11
75.5	3,277	410	0.1252	0.8748	12.36
76.5	3,530	1,036	0.2936	0.7064	10.82
77.5	2,493	1,100	0.4412	0.5588	7.64
78.5	1,393	507	0.3642	0.6358	4.27

THE POTOMAC EDISON COMPANY

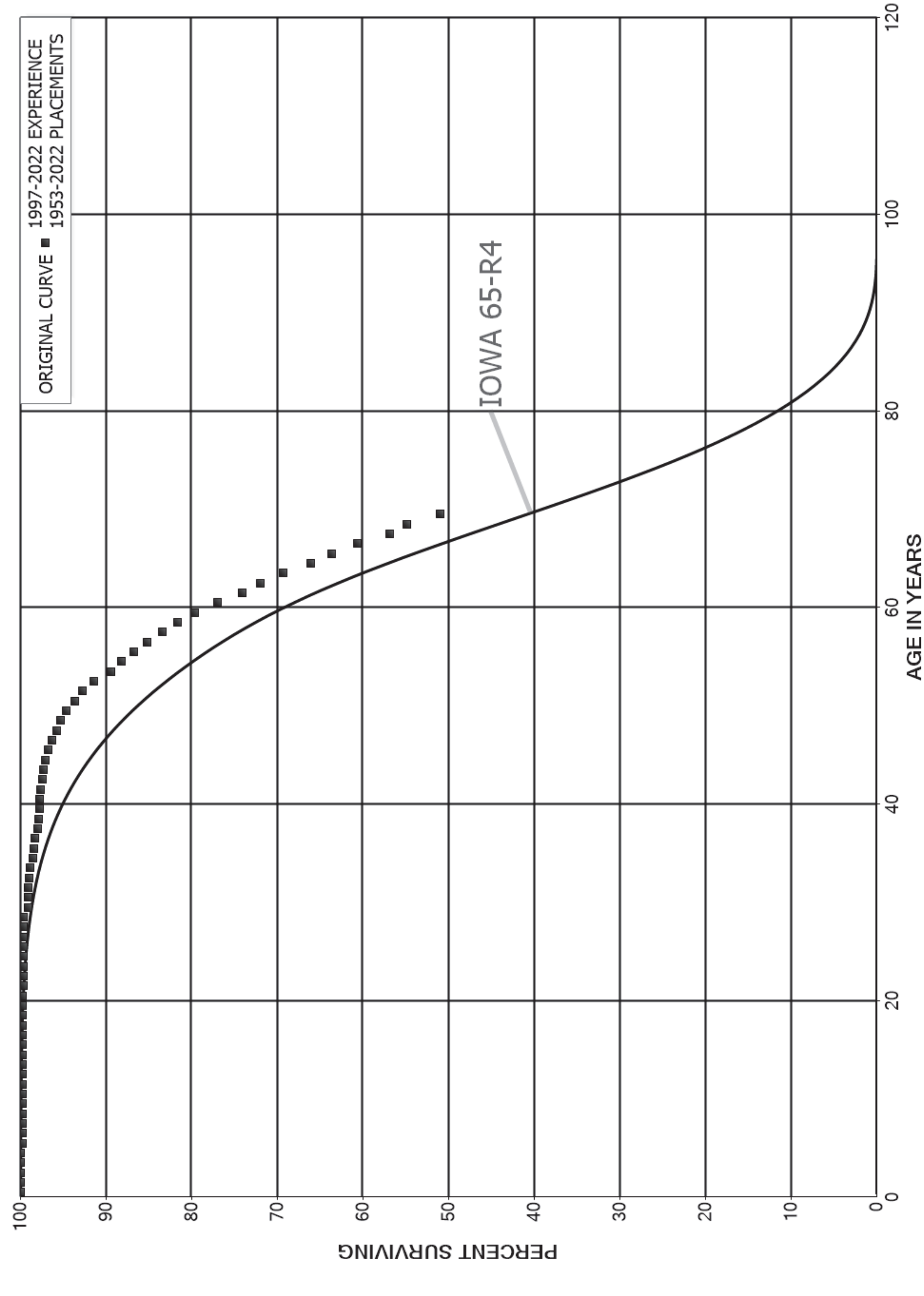
ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1916-2022 EXPERIENCE BAND 1997-2022

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	1,581	110	0.0697	0.9303	2.71
80.5	1,750	322	0.1838	0.8162	2.53
81.5	1,428	783	0.5480	0.4520	2.06
82.5	646	264	0.4095	0.5905	0.93
83.5	110	110	1.0000		0.55
84.5					

THE POTOMAC EDISON COMPANY
ACCOUNT 369.00 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1953-2022 EXPERIENCE BAND 1997-2022

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	40,334,078	8,105	0.0002	0.9998	100.00
0.5	40,500,654	1,397	0.0000	1.0000	99.98
1.5	39,780,386	119	0.0000	1.0000	99.98
2.5	38,563,431	183	0.0000	1.0000	99.98
3.5	38,530,747	348	0.0000	1.0000	99.98
4.5	37,916,268	82,057	0.0022	0.9978	99.97
5.5	36,885,179	126	0.0000	1.0000	99.76
6.5	36,602,529		0.0000	1.0000	99.76
7.5	36,609,810	123	0.0000	1.0000	99.76
8.5	36,470,770	495	0.0000	1.0000	99.76
9.5	36,020,308	2,241	0.0001	0.9999	99.76
10.5	36,121,187	384	0.0000	1.0000	99.75
11.5	35,927,999	15,986	0.0004	0.9996	99.75
12.5	36,407,442	4	0.0000	1.0000	99.70
13.5	36,757,005		0.0000	1.0000	99.70
14.5	36,854,947	3,216	0.0001	0.9999	99.70
15.5	35,418,608	774	0.0000	1.0000	99.70
16.5	36,297,087	1,541	0.0000	1.0000	99.69
17.5	36,869,506	465	0.0000	1.0000	99.69
18.5	37,588,983	988	0.0000	1.0000	99.69
19.5	38,295,053	3,762	0.0001	0.9999	99.69
20.5	39,165,355	9,912	0.0003	0.9997	99.68
21.5	34,360,111	10,117	0.0003	0.9997	99.65
22.5	34,811,619	1,434	0.0000	1.0000	99.62
23.5	35,556,152	3,295	0.0001	0.9999	99.62
24.5	31,215,991	1,543	0.0000	1.0000	99.61
25.5	30,979,913	1,406	0.0000	1.0000	99.60
26.5	28,780,768	702	0.0000	1.0000	99.60
27.5	27,802,223	969	0.0000	1.0000	99.60
28.5	26,446,062	148,381	0.0056	0.9944	99.59
29.5	24,126,944	2,263	0.0001	0.9999	99.03
30.5	22,620,239	2,249	0.0001	0.9999	99.02
31.5	21,138,633	10,183	0.0005	0.9995	99.01
32.5	19,168,374	24,374	0.0013	0.9987	98.97
33.5	17,528,593	52,829	0.0030	0.9970	98.84
34.5	16,223,060	22,056	0.0014	0.9986	98.54
35.5	15,250,498	25,863	0.0017	0.9983	98.41
36.5	14,258,939	37,425	0.0026	0.9974	98.24
37.5	13,418,901	25,800	0.0019	0.9981	97.98
38.5	12,527,532	6,581	0.0005	0.9995	97.80

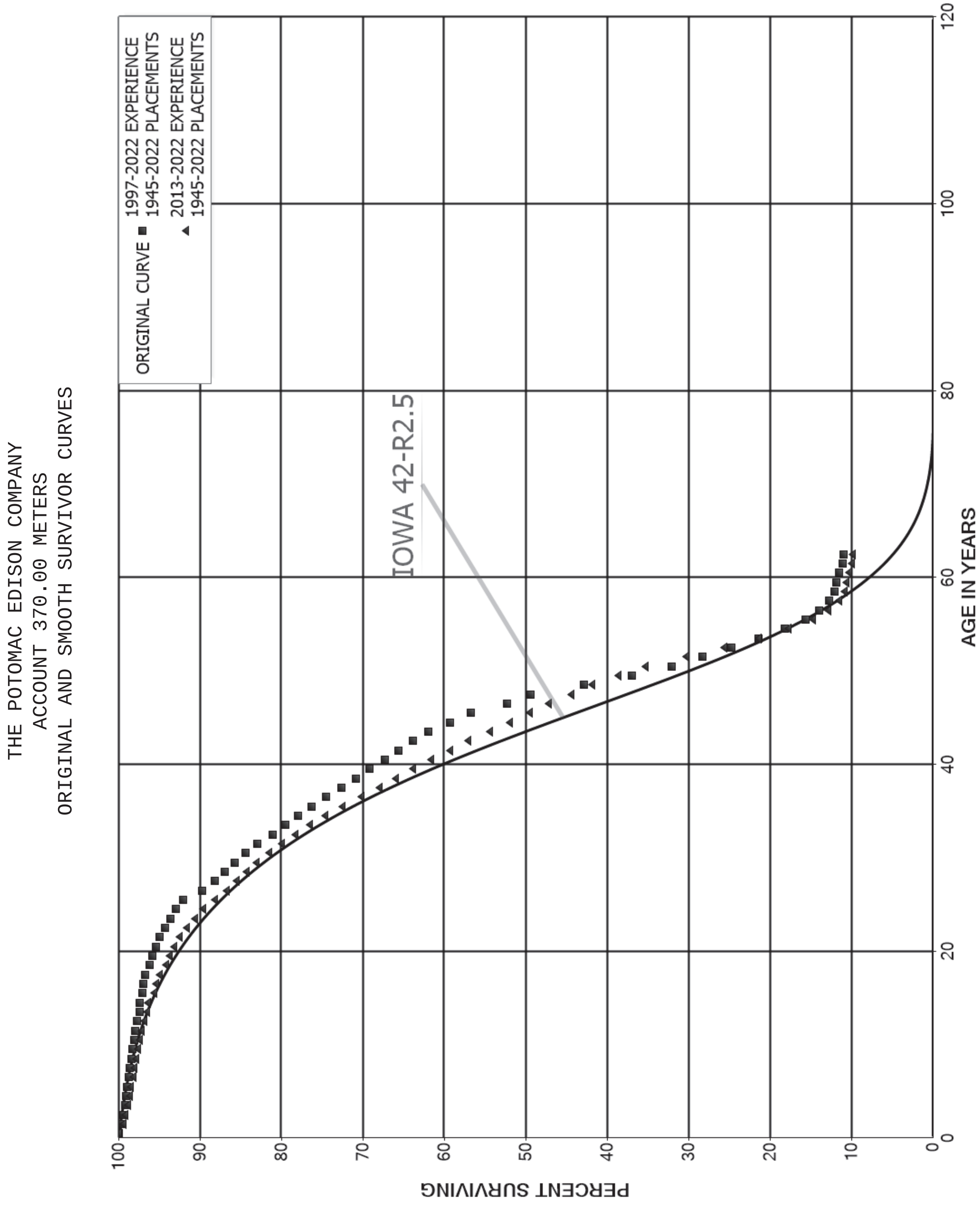
THE POTOMAC EDISON COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1953-2022 EXPERIENCE BAND 1997-2022

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	11,542,947	7,600	0.0007	0.9993	97.74
40.5	10,891,665	7,433	0.0007	0.9993	97.68
41.5	9,788,213	17,681	0.0018	0.9982	97.61
42.5	8,888,602	16,333	0.0018	0.9982	97.44
43.5	8,308,105	16,906	0.0020	0.9980	97.26
44.5	7,480,376	26,108	0.0035	0.9965	97.06
45.5	6,740,621	28,701	0.0043	0.9957	96.72
46.5	5,833,065	33,429	0.0057	0.9943	96.31
47.5	4,984,107	24,513	0.0049	0.9951	95.76
48.5	4,215,320	30,693	0.0073	0.9927	95.29
49.5	3,433,456	34,697	0.0101	0.9899	94.59
50.5	2,791,400	27,931	0.0100	0.9900	93.64
51.5	2,229,483	31,771	0.0143	0.9857	92.70
52.5	1,817,440	38,628	0.0213	0.9787	91.38
53.5	1,559,079	22,005	0.0141	0.9859	89.44
54.5	1,251,725	20,249	0.0162	0.9838	88.17
55.5	1,105,358	20,347	0.0184	0.9816	86.75
56.5	957,698	19,721	0.0206	0.9794	85.15
57.5	831,948	18,290	0.0220	0.9780	83.40
58.5	720,230	16,732	0.0232	0.9768	81.56
59.5	625,482	21,717	0.0347	0.9653	79.67
60.5	525,102	19,724	0.0376	0.9624	76.90
61.5	431,816	12,334	0.0286	0.9714	74.02
62.5	367,831	13,496	0.0367	0.9633	71.90
63.5	301,558	13,788	0.0457	0.9543	69.26
64.5	239,135	8,943	0.0374	0.9626	66.10
65.5	171,477	8,229	0.0480	0.9520	63.62
66.5	126,164	7,702	0.0610	0.9390	60.57
67.5	118,463	4,169	0.0352	0.9648	56.87
68.5	88,503	6,418	0.0725	0.9275	54.87
69.5					50.89


THE POTOMAC EDISON COMPANY
ACCOUNT 370.00 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1997-2022 EXPERIENCE
1945-2022 PLACEMENTS
▲ 2013-2022 EXPERIENCE
1945-2022 PLACEMENTS
IOWA 42-R2.5
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
0
20
40
60
80
100
120

THE POTOMAC EDISON COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1997-2022

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	40,827,460	44,319	0.0011	0.9989	100.00
0.5	40,246,056	155,517	0.0039	0.9961	99.89
1.5	41,473,994	57,959	0.0014	0.9986	99.51
2.5	38,142,418	72,392	0.0019	0.9981	99.37
3.5	37,915,408	47,937	0.0013	0.9987	99.18
4.5	35,777,390	54,315	0.0015	0.9985	99.05
5.5	33,438,117	64,772	0.0019	0.9981	98.90
6.5	32,779,547	32,025	0.0010	0.9990	98.71
7.5	30,828,020	67,144	0.0022	0.9978	98.61
8.5	30,904,789	36,571	0.0012	0.9988	98.40
9.5	29,903,993	74,396	0.0025	0.9975	98.28
10.5	29,534,079	36,565	0.0012	0.9988	98.04
11.5	28,761,227	55,519	0.0019	0.9981	97.92
12.5	28,097,236	93,347	0.0033	0.9967	97.73
13.5	28,034,422	14,568	0.0005	0.9995	97.40
14.5	27,918,462	83,806	0.0030	0.9970	97.35
15.5	25,758,895	35,470	0.0014	0.9986	97.06
16.5	26,053,441	58,473	0.0022	0.9978	96.93
17.5	25,817,866	149,193	0.0058	0.9942	96.71
18.5	26,094,151	92,128	0.0035	0.9965	96.15
19.5	26,397,608	113,759	0.0043	0.9957	95.81
20.5	26,617,266	132,651	0.0050	0.9950	95.40
21.5	24,767,461	164,011	0.0066	0.9934	94.92
22.5	23,216,046	159,938	0.0069	0.9931	94.29
23.5	23,320,735	173,751	0.0075	0.9925	93.64
24.5	19,819,074	198,670	0.0100	0.9900	92.95
25.5	19,551,243	494,725	0.0253	0.9747	92.01
26.5	18,917,540	323,414	0.0171	0.9829	89.69
27.5	14,244,108	193,110	0.0136	0.9864	88.15
28.5	12,903,339	175,375	0.0136	0.9864	86.96
29.5	12,013,273	193,461	0.0161	0.9839	85.78
30.5	11,369,130	200,230	0.0176	0.9824	84.39
31.5	10,378,717	230,020	0.0222	0.9778	82.91
32.5	9,450,315	185,604	0.0196	0.9804	81.07
33.5	8,531,172	165,614	0.0194	0.9806	79.48
34.5	7,628,596	163,346	0.0214	0.9786	77.94
35.5	7,020,523	164,893	0.0235	0.9765	76.27
36.5	6,453,638	160,149	0.0248	0.9752	74.48
37.5	5,937,129	144,071	0.0243	0.9757	72.63
38.5	5,365,420	129,978	0.0242	0.9758	70.87

THE POTOMAC EDISON COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1997-2022

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	4,837,041	127,857	0.0264	0.9736	69.15
40.5	4,464,926	110,294	0.0247	0.9753	67.32
41.5	4,019,011	110,657	0.0275	0.9725	65.66
42.5	3,628,093	108,364	0.0299	0.9701	63.85
43.5	3,446,445	145,898	0.0423	0.9577	61.94
44.5	3,030,266	133,769	0.0441	0.9559	59.32
45.5	2,657,677	205,996	0.0775	0.9225	56.70
46.5	2,238,483	122,603	0.0548	0.9452	52.31
47.5	1,985,478	264,583	0.1333	0.8667	49.44
48.5	1,495,666	206,038	0.1378	0.8622	42.85
49.5	1,100,641	145,724	0.1324	0.8676	36.95
50.5	895,936	104,609	0.1168	0.8832	32.06
51.5	754,286	96,483	0.1279	0.8721	28.31
52.5	609,473	82,680	0.1357	0.8643	24.69
53.5	493,454	73,671	0.1493	0.8507	21.34
54.5	383,159	53,714	0.1402	0.8598	18.16
55.5	300,692	32,441	0.1079	0.8921	15.61
56.5	231,589	20,017	0.0864	0.9136	13.93
57.5	189,013	9,432	0.0499	0.9501	12.72
58.5	161,925	3,133	0.0193	0.9807	12.09
59.5	142,240	3,911	0.0275	0.9725	11.85
60.5	134,940	5,155	0.0382	0.9618	11.53
61.5	114,488	1,251	0.0109	0.9891	11.09
62.5	94,375		0.0000	1.0000	10.97
63.5	74,491	6	0.0001	0.9999	10.97
64.5	59,312	3	0.0000	1.0000	10.97
65.5	47,291		0.0000	1.0000	10.97
66.5	28,074		0.0000	1.0000	10.97
67.5	20,624	523	0.0254	0.9746	10.97
68.5	13,184		0.0000	1.0000	10.69
69.5					10.69

THE POTOMAC EDISON COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 2013-2022

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	24,577,165	39,721	0.0016	0.9984	100.00
0.5	24,121,778	143,353	0.0059	0.9941	99.84
1.5	21,960,162	49,054	0.0022	0.9978	99.25
2.5	18,533,408	64,598	0.0035	0.9965	99.02
3.5	17,894,618	28,534	0.0016	0.9984	98.68
4.5	15,600,092	28,161	0.0018	0.9982	98.52
5.5	14,915,622	35,216	0.0024	0.9976	98.34
6.5	13,416,333	21,900	0.0016	0.9984	98.11
7.5	10,977,797	28,900	0.0026	0.9974	97.95
8.5	10,004,036	17,810	0.0018	0.9982	97.69
9.5	8,373,246	16,682	0.0020	0.9980	97.52
10.5	7,406,697	18,198	0.0025	0.9975	97.32
11.5	7,967,592	30,284	0.0038	0.9962	97.09
12.5	8,421,118	29,713	0.0035	0.9965	96.72
13.5	7,727,952	9,692	0.0013	0.9987	96.38
14.5	11,089,117	81,232	0.0073	0.9927	96.25
15.5	8,641,757	27,339	0.0032	0.9968	95.55
16.5	8,794,325	38,028	0.0043	0.9957	95.25
17.5	13,255,543	113,242	0.0085	0.9915	94.84
18.5	14,563,304	65,949	0.0045	0.9955	94.02
19.5	15,412,884	90,178	0.0059	0.9941	93.60
20.5	15,947,876	117,916	0.0074	0.9926	93.05
21.5	15,003,298	145,402	0.0097	0.9903	92.36
22.5	14,111,464	151,569	0.0107	0.9893	91.47
23.5	14,959,018	167,127	0.0112	0.9888	90.49
24.5	12,186,176	191,457	0.0157	0.9843	89.47
25.5	12,399,642	206,914	0.0167	0.9833	88.07
26.5	12,560,555	168,272	0.0134	0.9866	86.60
27.5	8,610,929	125,179	0.0145	0.9855	85.44
28.5	7,914,463	120,020	0.0152	0.9848	84.20
29.5	7,673,695	137,284	0.0179	0.9821	82.92
30.5	7,294,169	140,345	0.0192	0.9808	81.44
31.5	6,747,060	143,880	0.0213	0.9787	79.87
32.5	6,152,634	141,797	0.0230	0.9770	78.17
33.5	5,444,200	132,954	0.0244	0.9756	76.37
34.5	4,812,067	138,357	0.0288	0.9712	74.50
35.5	4,495,841	142,543	0.0317	0.9683	72.36
36.5	4,144,878	131,799	0.0318	0.9682	70.06
37.5	3,667,803	109,853	0.0300	0.9700	67.84
38.5	3,378,600	107,944	0.0319	0.9681	65.80

THE POTOMAC EDISON COMPANY

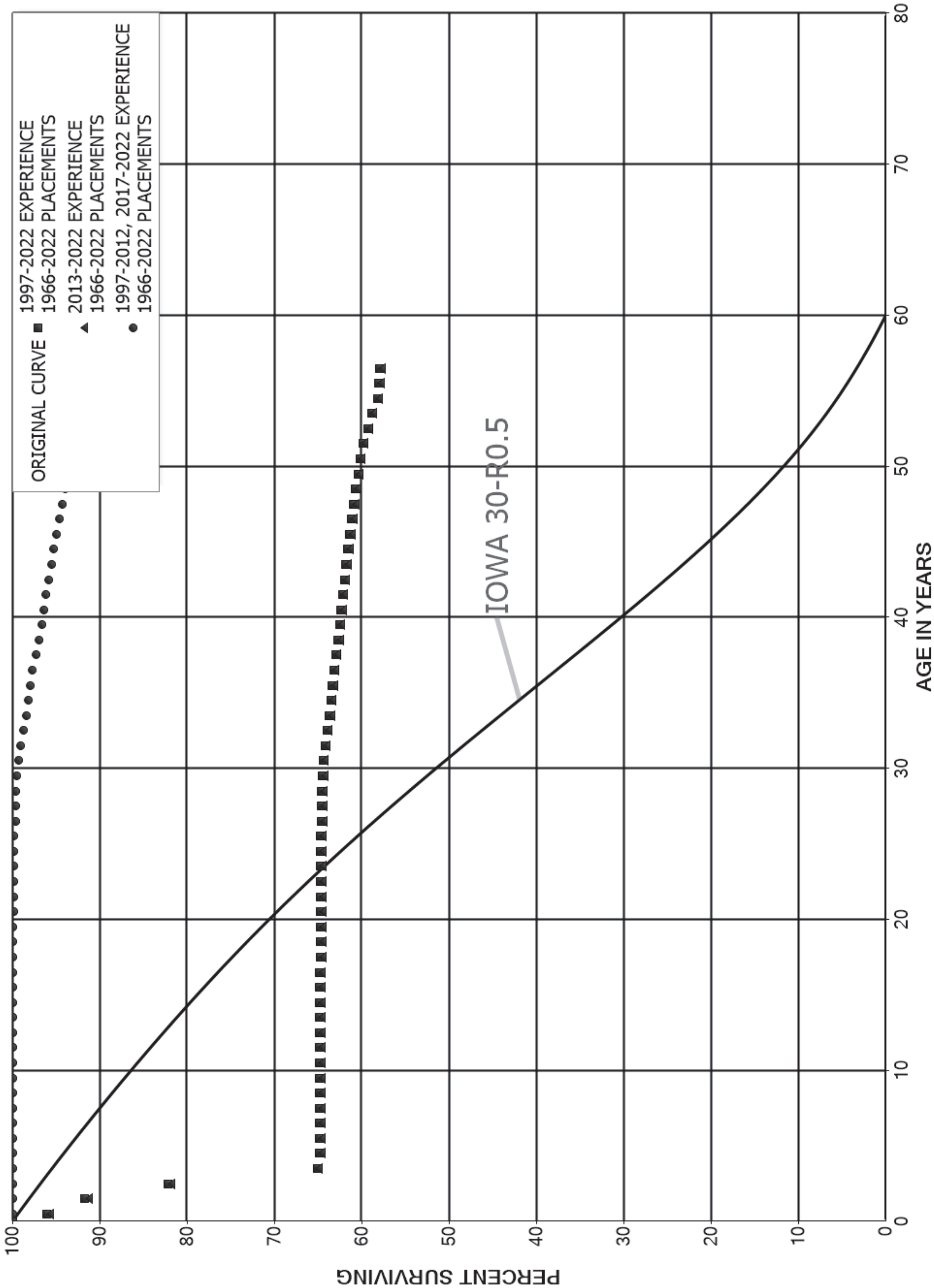
ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 2013-2022

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	3,027,059	106,929	0.0353	0.9647	63.70
40.5	2,758,123	100,012	0.0363	0.9637	61.45
41.5	2,359,654	91,991	0.0390	0.9610	59.22
42.5	2,058,900	94,977	0.0461	0.9539	56.91
43.5	1,771,222	81,118	0.0458	0.9542	54.29
44.5	1,508,011	70,244	0.0466	0.9534	51.80
45.5	1,291,031	62,107	0.0481	0.9519	49.39
46.5	1,150,412	66,779	0.0580	0.9420	47.01
47.5	1,073,403	62,610	0.0583	0.9417	44.28
48.5	943,687	71,605	0.0759	0.9241	41.70
49.5	814,701	71,668	0.0880	0.9120	38.54
50.5	744,106	104,464	0.1404	0.8596	35.15
51.5	610,628	95,987	0.1572	0.8428	30.21
52.5	486,971	79,615	0.1635	0.8365	25.46
53.5	396,032	68,052	0.1718	0.8282	21.30
54.5	307,703	51,943	0.1688	0.8312	17.64
55.5	240,596	32,196	0.1338	0.8662	14.66
56.5	192,171	20,017	0.1042	0.8958	12.70
57.5	158,642	9,432	0.0595	0.9405	11.38
58.5	138,822	3,127	0.0225	0.9775	10.70
59.5	141,711	3,911	0.0276	0.9724	10.46
60.5	134,411	5,155	0.0384	0.9616	10.17
61.5	113,960	1,251	0.0110	0.9890	9.78
62.5	93,846		0.0000	1.0000	9.67
63.5	73,962		0.0000	1.0000	9.67
64.5	58,789	3	0.0000	1.0000	9.67
65.5	46,768		0.0000	1.0000	9.67
66.5	27,551		0.0000	1.0000	9.67
67.5	20,624	523	0.0254	0.9746	9.67
68.5	13,184		0.0000	1.0000	9.43
69.5					9.43

THE POTOMAC EDISON COMPANY
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2022 EXPERIENCE BAND 1997-2022

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	655,704	25,484	0.0389	0.9611	100.00
0.5	618,771	28,545	0.0461	0.9539	96.11
1.5	419,700	43,590	0.1039	0.8961	91.68
2.5	340,711	70,744	0.2076	0.7924	82.16
3.5	230,090	1,042	0.0045	0.9955	65.10
4.5	509,364		0.0000	1.0000	64.80
5.5	597,107		0.0000	1.0000	64.80
6.5	593,283		0.0000	1.0000	64.80
7.5	784,568		0.0000	1.0000	64.80
8.5	724,659		0.0000	1.0000	64.80
9.5	710,727		0.0000	1.0000	64.80
10.5	726,248		0.0000	1.0000	64.80
11.5	427,744		0.0000	1.0000	64.80
12.5	324,163		0.0000	1.0000	64.80
13.5	296,846		0.0000	1.0000	64.80
14.5	278,650		0.0000	1.0000	64.80
15.5	274,910		0.0000	1.0000	64.80
16.5	274,414	263	0.0010	0.9990	64.80
17.5	360,617	41	0.0001	0.9999	64.74
18.5	356,895	41	0.0001	0.9999	64.73
19.5	363,195	41	0.0001	0.9999	64.73
20.5	366,271	41	0.0001	0.9999	64.72
21.5	148,328	41	0.0003	0.9997	64.71
22.5	137,898		0.0000	1.0000	64.70
23.5	144,324	41	0.0003	0.9997	64.70
24.5	61,844		0.0000	1.0000	64.68
25.5	69,549	105	0.0015	0.9985	64.68
26.5	74,865		0.0000	1.0000	64.58
27.5	80,101		0.0000	1.0000	64.58
28.5	77,333	112	0.0015	0.9985	64.58
29.5	98,290	98	0.0010	0.9990	64.49
30.5	135,643	442	0.0033	0.9967	64.42
31.5	152,566	545	0.0036	0.9964	64.21
32.5	169,033	710	0.0042	0.9958	63.98
33.5	201,623	582	0.0029	0.9971	63.71
34.5	211,298	494	0.0023	0.9977	63.53
35.5	245,954	679	0.0028	0.9972	63.38
36.5	229,262	813	0.0035	0.9965	63.21
37.5	192,177	836	0.0044	0.9956	62.98
38.5	169,493	485	0.0029	0.9971	62.71

THE POTOMAC EDISON COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2022 EXPERIENCE BAND 1997-2022

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	153,918	340	0.0022	0.9978	62.53
40.5	118,423	311	0.0026	0.9974	62.39
41.5	112,478	426	0.0038	0.9962	62.23
42.5	94,776	241	0.0025	0.9975	61.99
43.5	115,083	456	0.0040	0.9960	61.83
44.5	115,130	434	0.0038	0.9962	61.59
45.5	116,050	396	0.0034	0.9966	61.35
46.5	130,925	502	0.0038	0.9962	61.15
47.5	154,037	598	0.0039	0.9961	60.91
48.5	156,166	607	0.0039	0.9961	60.67
49.5	158,099	626	0.0040	0.9960	60.44
50.5	124,521	703	0.0056	0.9944	60.20
51.5	116,741	1,099	0.0094	0.9906	59.86
52.5	98,830	765	0.0077	0.9923	59.30
53.5	74,210	798	0.0108	0.9892	58.84
54.5	40,113	128	0.0032	0.9968	58.20
55.5	26,260	45	0.0017	0.9983	58.02
56.5					57.92

THE POTOMAC EDISON COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2022 EXPERIENCE BAND 2013-2022

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	567,669	25,484	0.0449	0.9551	100.00
0.5	618,771	28,545	0.0461	0.9539	95.51
1.5	419,700	43,590	0.1039	0.8961	91.10
2.5	340,711	70,744	0.2076	0.7924	81.64
3.5	230,090	1,042	0.0045	0.9955	64.69
4.5	509,364		0.0000	1.0000	64.40
5.5	597,107		0.0000	1.0000	64.40
6.5	593,283		0.0000	1.0000	64.40
7.5	784,568		0.0000	1.0000	64.40
8.5	724,659		0.0000	1.0000	64.40
9.5	710,727		0.0000	1.0000	64.40
10.5	726,248		0.0000	1.0000	64.40
11.5	427,744		0.0000	1.0000	64.40
12.5	324,163		0.0000	1.0000	64.40
13.5	296,846		0.0000	1.0000	64.40
14.5	278,650		0.0000	1.0000	64.40
15.5	274,910		0.0000	1.0000	64.40
16.5	274,414	263	0.0010	0.9990	64.40
17.5	360,617	41	0.0001	0.9999	64.34
18.5	356,895	41	0.0001	0.9999	64.33
19.5	363,195	41	0.0001	0.9999	64.32
20.5	366,271	41	0.0001	0.9999	64.31
21.5	148,328	41	0.0003	0.9997	64.31
22.5	137,898		0.0000	1.0000	64.29
23.5	144,324	41	0.0003	0.9997	64.29
24.5	61,844		0.0000	1.0000	64.27
25.5	69,549	105	0.0015	0.9985	64.27
26.5	74,865		0.0000	1.0000	64.17
27.5	80,101		0.0000	1.0000	64.17
28.5	77,333	112	0.0015	0.9985	64.17
29.5	98,290	98	0.0010	0.9990	64.08
30.5	135,643	442	0.0033	0.9967	64.02
31.5	152,566	545	0.0036	0.9964	63.81
32.5	169,033	710	0.0042	0.9958	63.58
33.5	201,623	582	0.0029	0.9971	63.31
34.5	211,298	494	0.0023	0.9977	63.13
35.5	245,954	679	0.0028	0.9972	62.98
36.5	229,262	813	0.0035	0.9965	62.81
37.5	192,177	836	0.0044	0.9956	62.59
38.5	169,493	485	0.0029	0.9971	62.31

THE POTOMAC EDISON COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2022 EXPERIENCE BAND 2013-2022

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	153,918	340	0.0022	0.9978	62.14
40.5	118,423	311	0.0026	0.9974	62.00
41.5	112,478	426	0.0038	0.9962	61.84
42.5	94,776	241	0.0025	0.9975	61.60
43.5	115,083	456	0.0040	0.9960	61.44
44.5	115,130	434	0.0038	0.9962	61.20
45.5	116,050	396	0.0034	0.9966	60.97
46.5	130,925	502	0.0038	0.9962	60.76
47.5	154,037	598	0.0039	0.9961	60.53
48.5	156,166	607	0.0039	0.9961	60.29
49.5	158,099	626	0.0040	0.9960	60.06
50.5	124,521	703	0.0056	0.9944	59.82
51.5	116,741	1,099	0.0094	0.9906	59.48
52.5	98,830	765	0.0077	0.9923	58.92
53.5	74,210	798	0.0108	0.9892	58.47
54.5	40,113	128	0.0032	0.9968	57.84
55.5	26,260	45	0.0017	0.9983	57.65
56.5					57.55

THE POTOMAC EDISON COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2022 EXPERIENCE BAND 1997-2012, 2017-2022

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	386,525		0.0000	1.0000	100.00
0.5	318,183		0.0000	1.0000	100.00
1.5	204,274		0.0000	1.0000	100.00
2.5	252,033		0.0000	1.0000	100.00
3.5	226,676		0.0000	1.0000	100.00
4.5	206,941		0.0000	1.0000	100.00
5.5	490,233		0.0000	1.0000	100.00
6.5	565,966		0.0000	1.0000	100.00
7.5	536,666		0.0000	1.0000	100.00
8.5	701,409		0.0000	1.0000	100.00
9.5	710,138		0.0000	1.0000	100.00
10.5	708,355		0.0000	1.0000	100.00
11.5	423,824		0.0000	1.0000	100.00
12.5	320,870		0.0000	1.0000	100.00
13.5	296,846		0.0000	1.0000	100.00
14.5	48,943		0.0000	1.0000	100.00
15.5	255,400		0.0000	1.0000	100.00
16.5	274,321	263	0.0010	0.9990	100.00
17.5	256,259		0.0000	1.0000	99.90
18.5	356,656	41	0.0001	0.9999	99.90
19.5	353,562	41	0.0001	0.9999	99.89
20.5	363,154	41	0.0001	0.9999	99.88
21.5	136,786	41	0.0003	0.9997	99.87
22.5	128,777		0.0000	1.0000	99.84
23.5	137,805	41	0.0003	0.9997	99.84
24.5	40,170		0.0000	1.0000	99.81
25.5	61,605	105	0.0017	0.9983	99.81
26.5	59,811		0.0000	1.0000	99.64
27.5	71,749		0.0000	1.0000	99.64
28.5	68,558	112	0.0016	0.9984	99.64
29.5	68,101	98	0.0014	0.9986	99.48
30.5	91,672	263	0.0029	0.9971	99.33
31.5	113,631	330	0.0029	0.9971	99.05
32.5	144,077	545	0.0038	0.9962	98.76
33.5	153,382	394	0.0026	0.9974	98.39
34.5	192,787	353	0.0018	0.9982	98.14
35.5	202,141	526	0.0026	0.9974	97.96
36.5	215,690	813	0.0038	0.9962	97.70
37.5	185,372	836	0.0045	0.9955	97.33
38.5	153,267	379	0.0025	0.9975	96.89

THE POTOMAC EDISON COMPANY

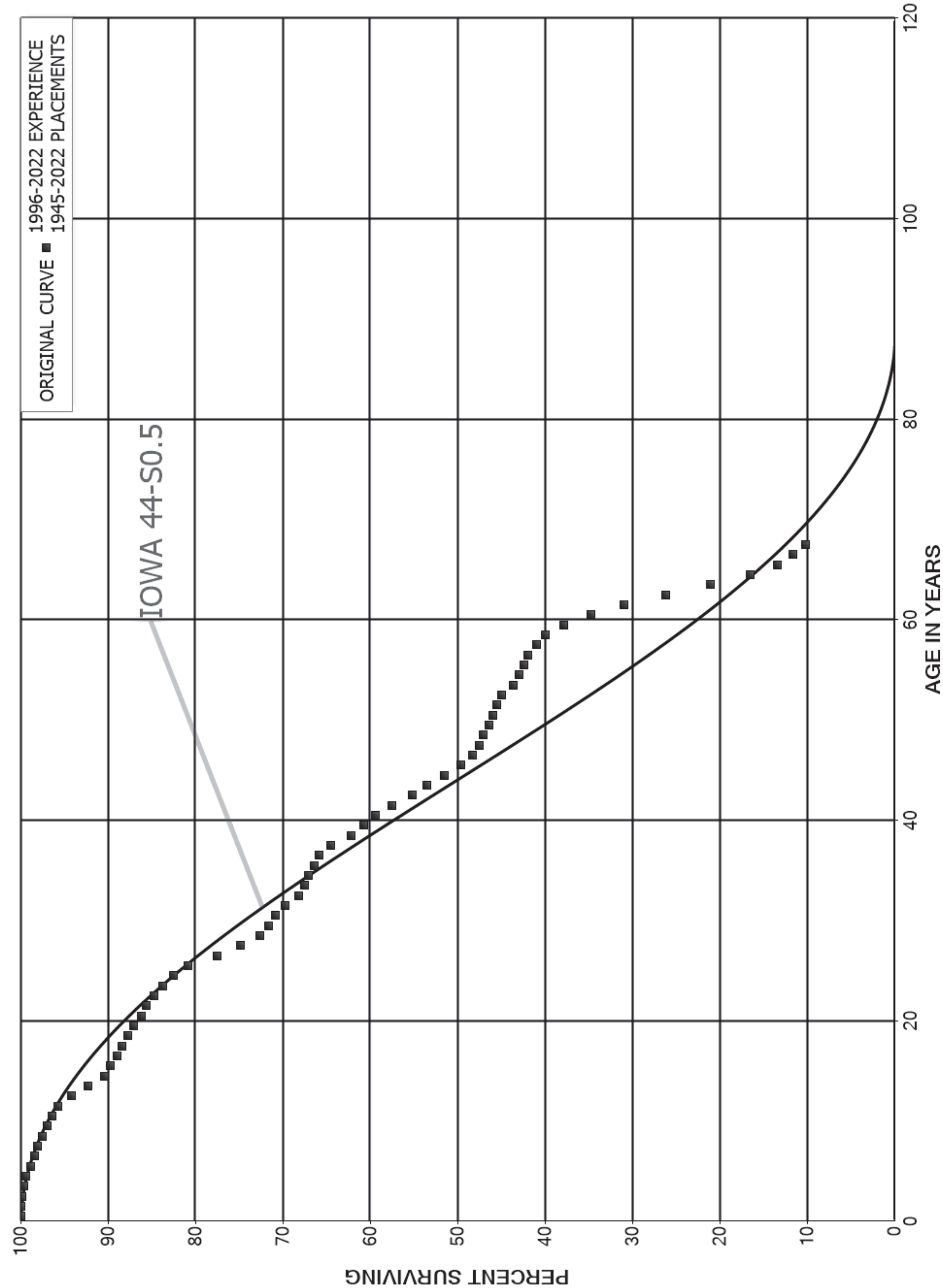
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2022 EXPERIENCE BAND 1997-2012, 2017-2022

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	144,382	340	0.0024	0.9976	96.65
40.5	106,651	311	0.0029	0.9971	96.43
41.5	99,884	366	0.0037	0.9963	96.14
42.5	69,460	174	0.0025	0.9975	95.79
43.5	81,219	261	0.0032	0.9968	95.55
44.5	107,920	389	0.0036	0.9964	95.24
45.5	98,788	307	0.0031	0.9969	94.90
46.5	106,316	376	0.0035	0.9965	94.61
47.5	118,879	448	0.0038	0.9962	94.27
48.5	141,144	531	0.0038	0.9962	93.92
49.5	130,846	490	0.0037	0.9963	93.56
50.5	124,521	703	0.0056	0.9944	93.21
51.5	116,741	1,099	0.0094	0.9906	92.69
52.5	98,830	765	0.0077	0.9923	91.81
53.5	74,210	798	0.0108	0.9892	91.10
54.5	40,113	128	0.0032	0.9968	90.12
55.5	26,260	45	0.0017	0.9983	89.83
56.5					89.68

THE POTOMAC EDISON COMPANY
ACCOUNTS 373.10 STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNTS 373.10 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1996-2022

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	30,272,826	8,960	0.0003	0.9997	100.00
0.5	30,841,350	22,847	0.0007	0.9993	99.97
1.5	30,349,981	21,970	0.0007	0.9993	99.90
2.5	29,782,576	64,363	0.0022	0.9978	99.82
3.5	29,260,508	58,682	0.0020	0.9980	99.61
4.5	28,551,777	170,115	0.0060	0.9940	99.41
5.5	27,625,742	102,670	0.0037	0.9963	98.82
6.5	27,007,709	108,196	0.0040	0.9960	98.45
7.5	25,781,869	134,764	0.0052	0.9948	98.05
8.5	25,116,828	161,041	0.0064	0.9936	97.54
9.5	24,563,158	134,481	0.0055	0.9945	96.92
10.5	23,766,380	162,267	0.0068	0.9932	96.39
11.5	18,418,741	297,633	0.0162	0.9838	95.73
12.5	16,212,970	325,073	0.0201	0.9799	94.18
13.5	15,796,550	330,664	0.0209	0.9791	92.29
14.5	13,796,078	91,179	0.0066	0.9934	90.36
15.5	13,221,446	115,888	0.0088	0.9912	89.76
16.5	12,967,793	79,904	0.0062	0.9938	88.98
17.5	12,750,197	102,359	0.0080	0.9920	88.43
18.5	12,658,391	100,512	0.0079	0.9921	87.72
19.5	12,491,099	113,956	0.0091	0.9909	87.02
20.5	12,356,123	86,478	0.0070	0.9930	86.23
21.5	9,566,826	101,386	0.0106	0.9894	85.62
22.5	9,314,945	111,320	0.0120	0.9880	84.72
23.5	9,281,116	137,047	0.0148	0.9852	83.70
24.5	7,303,406	147,218	0.0202	0.9798	82.47
25.5	5,761,830	234,854	0.0408	0.9592	80.81
26.5	5,015,998	175,948	0.0351	0.9649	77.51
27.5	4,310,279	124,556	0.0289	0.9711	74.79
28.5	3,803,211	52,029	0.0137	0.9863	72.63
29.5	3,393,519	40,215	0.0119	0.9881	71.64
30.5	3,011,494	44,258	0.0147	0.9853	70.79
31.5	2,562,425	58,096	0.0227	0.9773	69.75
32.5	2,324,145	24,395	0.0105	0.9895	68.17
33.5	2,017,530	12,311	0.0061	0.9939	67.45
34.5	1,788,417	15,861	0.0089	0.9911	67.04
35.5	1,639,533	15,585	0.0095	0.9905	66.45
36.5	1,475,293	30,294	0.0205	0.9795	65.81
37.5	1,356,404	47,092	0.0347	0.9653	64.46
38.5	1,240,072	29,172	0.0235	0.9765	62.23

THE POTOMAC EDISON COMPANY

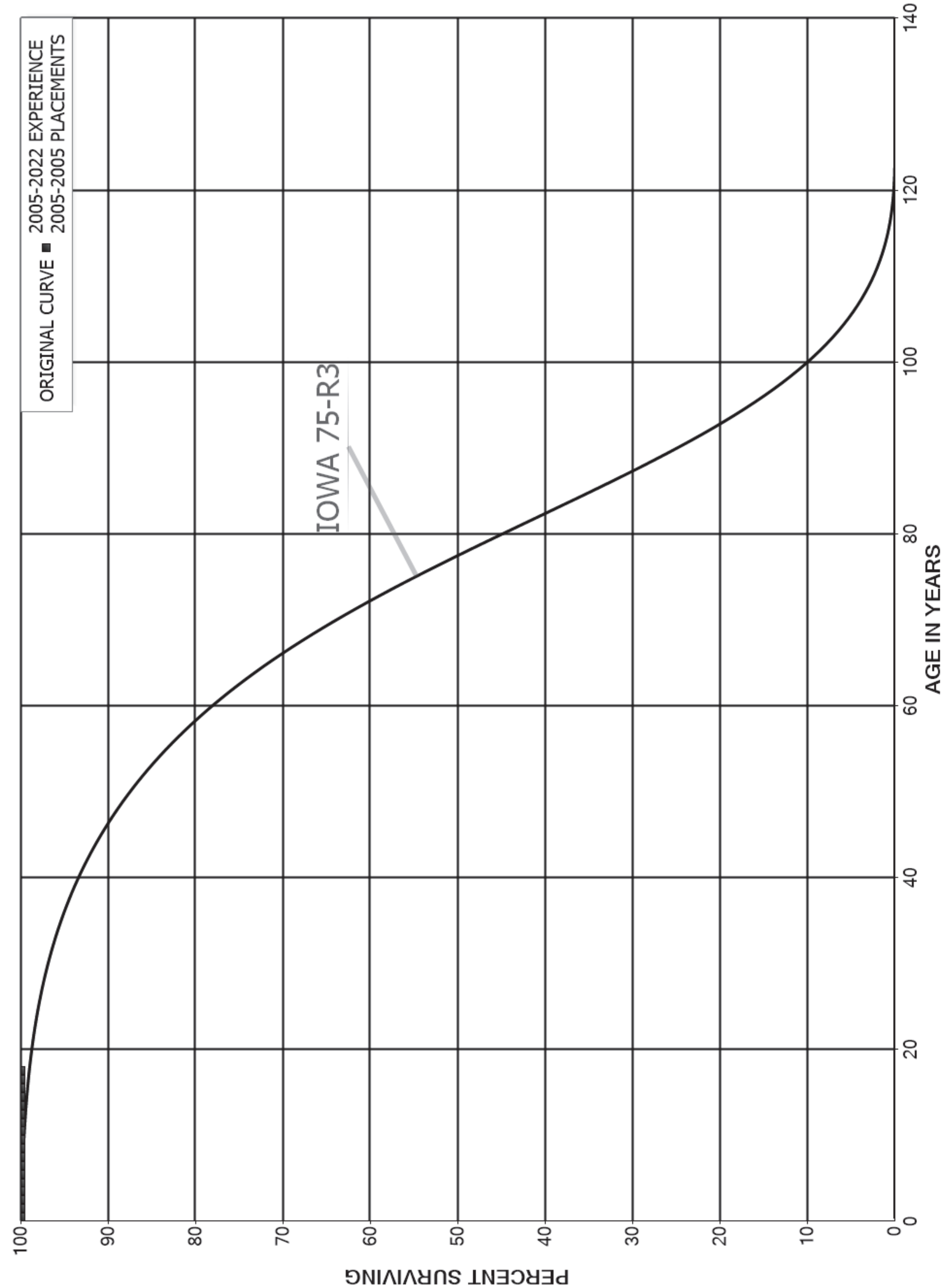
ACCOUNTS 373.10 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1945-2022 EXPERIENCE BAND 1996-2022

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	1,164,952	26,963	0.0231	0.9769	60.76
40.5	1,073,466	34,347	0.0320	0.9680	59.36
41.5	980,598	39,357	0.0401	0.9599	57.46
42.5	847,586	25,989	0.0307	0.9693	55.15
43.5	750,249	27,086	0.0361	0.9639	53.46
44.5	660,132	24,775	0.0375	0.9625	51.53
45.5	564,398	15,338	0.0272	0.9728	49.60
46.5	497,812	7,374	0.0148	0.9852	48.25
47.5	399,986	4,213	0.0105	0.9895	47.53
48.5	327,919	4,190	0.0128	0.9872	47.03
49.5	241,537	2,721	0.0113	0.9887	46.43
50.5	213,558	1,874	0.0088	0.9912	45.91
51.5	171,573	2,239	0.0130	0.9870	45.51
52.5	155,331	4,671	0.0301	0.9699	44.91
53.5	127,211	1,834	0.0144	0.9856	43.56
54.5	96,613	1,238	0.0128	0.9872	42.93
55.5	67,491	757	0.0112	0.9888	42.38
56.5	38,711	861	0.0222	0.9778	41.91
57.5	37,582	914	0.0243	0.9757	40.98
58.5	36,475	1,983	0.0544	0.9456	39.98
59.5	33,351	2,758	0.0827	0.9173	37.80
60.5	30,451	3,324	0.1091	0.8909	34.68
61.5	26,944	4,078	0.1513	0.8487	30.89
62.5	18,827	3,711	0.1971	0.8029	26.22
63.5	14,968	3,211	0.2145	0.7855	21.05
64.5	11,757	2,220	0.1888	0.8112	16.53
65.5	9,131	1,216	0.1331	0.8669	13.41
66.5	6,597	809	0.1227	0.8773	11.63
67.5	4,910	410	0.0835	0.9165	10.20
68.5	3,186	91	0.0286	0.9714	9.35
69.5	1,827	236	0.1291	0.8709	9.08
70.5	1,591	471	0.2964	0.7036	7.91
71.5	1,119	236	0.2106	0.7894	5.56
72.5	884	236	0.2668	0.7332	4.39
73.5	648	118	0.1819	0.8181	3.22
74.5	530		0.0000	1.0000	2.64
75.5	530		0.0000	1.0000	2.64
76.5	530		0.0000	1.0000	2.64
77.5					2.64

THE POTOMAC EDISON COMPANY
ACCOUNT 389.20 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

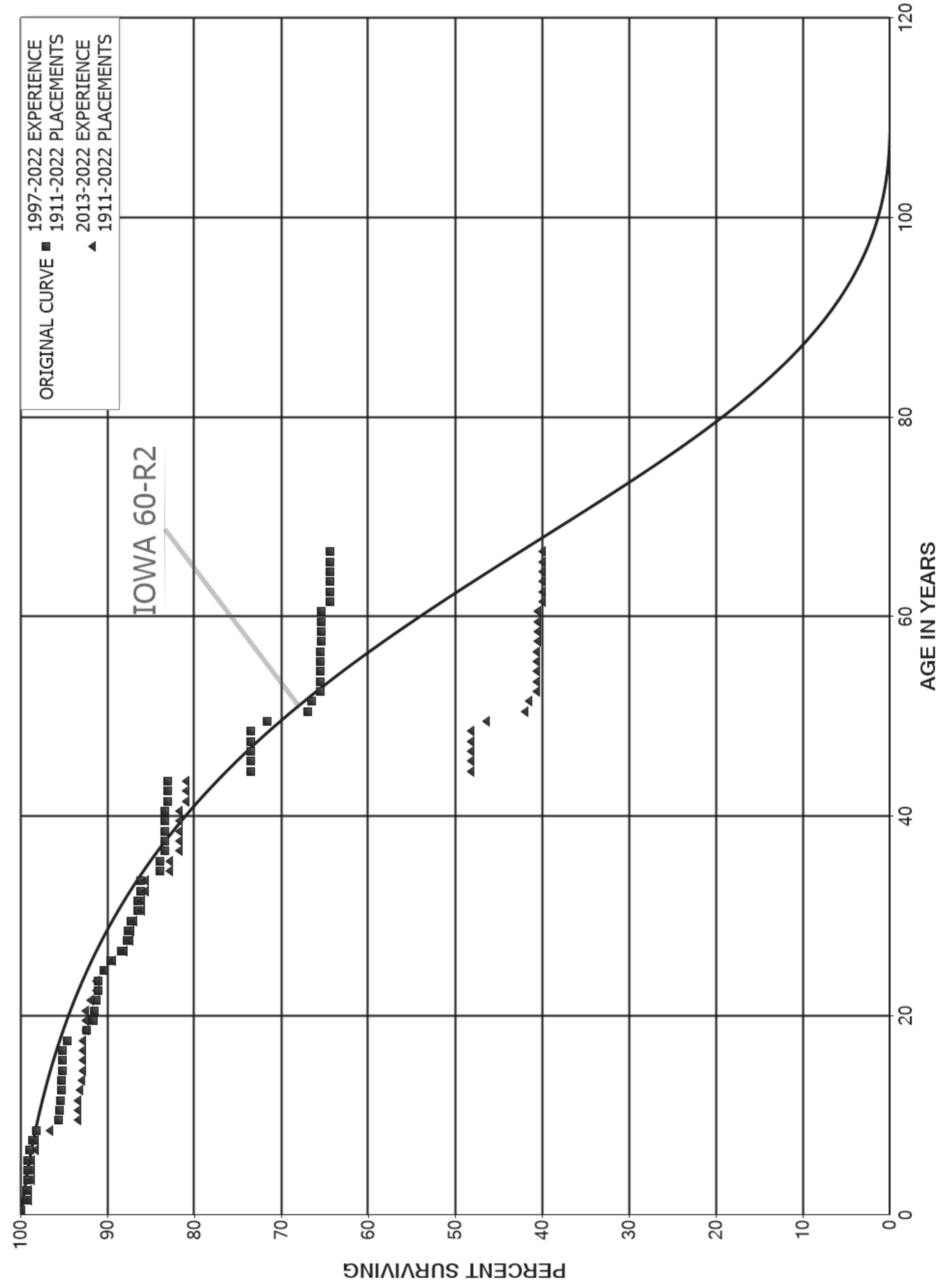
ACCOUNT 389.20 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 2005-2005 EXPERIENCE BAND 2005-2022

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	3,778		0.0000	1.0000	100.00
0.5	3,778		0.0000	1.0000	100.00
1.5	3,778		0.0000	1.0000	100.00
2.5	3,778		0.0000	1.0000	100.00
3.5	3,778		0.0000	1.0000	100.00
4.5	3,778		0.0000	1.0000	100.00
5.5	3,778		0.0000	1.0000	100.00
6.5	3,778		0.0000	1.0000	100.00
7.5	3,778		0.0000	1.0000	100.00
8.5	3,778		0.0000	1.0000	100.00
9.5	3,778		0.0000	1.0000	100.00
10.5	3,778		0.0000	1.0000	100.00
11.5	3,778		0.0000	1.0000	100.00
12.5	3,778		0.0000	1.0000	100.00
13.5	3,778		0.0000	1.0000	100.00
14.5	3,778		0.0000	1.0000	100.00
15.5	3,778		0.0000	1.0000	100.00
16.5	3,778		0.0000	1.0000	100.00
17.5					100.00

THE POTOMAC EDISON COMPANY
ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1911-2022 EXPERIENCE BAND 1997-2022

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	17,114,466		0.0000	1.0000	100.00
0.5	17,254,711	116,073	0.0067	0.9933	100.00
1.5	17,739,041		0.0000	1.0000	99.33
2.5	17,586,707	24,389	0.0014	0.9986	99.33
3.5	18,707,539	1,754	0.0001	0.9999	99.19
4.5	18,596,685	6,367	0.0003	0.9997	99.18
5.5	23,507,182	56,413	0.0024	0.9976	99.15
6.5	22,156,412	70,062	0.0032	0.9968	98.91
7.5	23,026,735	87,176	0.0038	0.9962	98.60
8.5	25,289,696	684,666	0.0271	0.9729	98.22
9.5	26,205,537	29,939	0.0011	0.9989	95.56
10.5	23,694,267	22,644	0.0010	0.9990	95.45
11.5	23,535,235	16,001	0.0007	0.9993	95.36
12.5	22,538,867	10,967	0.0005	0.9995	95.30
13.5	21,710,466	20,720	0.0010	0.9990	95.25
14.5	17,893,626		0.0000	1.0000	95.16
15.5	17,564,614		0.0000	1.0000	95.16
16.5	16,672,656	89,631	0.0054	0.9946	95.16
17.5	16,524,042	400,666	0.0242	0.9758	94.65
18.5	15,572,749	131,566	0.0084	0.9916	92.35
19.5	14,899,906	17,024	0.0011	0.9989	91.57
20.5	13,997,947	28,741	0.0021	0.9979	91.47
21.5	12,128,373	31,853	0.0026	0.9974	91.28
22.5	12,034,214		0.0000	1.0000	91.04
23.5	12,158,977	81,501	0.0067	0.9933	91.04
24.5	11,732,272	100,331	0.0086	0.9914	90.43
25.5	11,477,587	166,752	0.0145	0.9855	89.66
26.5	11,128,852	83,338	0.0075	0.9925	88.36
27.5	10,797,087	11,922	0.0011	0.9989	87.69
28.5	10,558,159	33,172	0.0031	0.9969	87.60
29.5	9,776,587	87,821	0.0090	0.9910	87.32
30.5	8,676,234		0.0000	1.0000	86.54
31.5	8,102,096	38,228	0.0047	0.9953	86.54
32.5	6,348,230	564	0.0001	0.9999	86.13
33.5	5,139,413	129,729	0.0252	0.9748	86.12
34.5	2,649,167		0.0000	1.0000	83.95
35.5	1,922,727	11,981	0.0062	0.9938	83.95
36.5	1,644,341	1,333	0.0008	0.9992	83.42
37.5	1,522,920		0.0000	1.0000	83.36
38.5	1,761,033		0.0000	1.0000	83.36

THE POTOMAC EDISON COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2022 EXPERIENCE BAND 1997-2022

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	1,741,457		0.0000	1.0000	83.36
40.5	1,734,557	6,322	0.0036	0.9964	83.36
41.5	1,673,737		0.0000	1.0000	83.05
42.5	1,428,879		0.0000	1.0000	83.05
43.5	1,397,442	160,052	0.1145	0.8855	83.05
44.5	1,216,253		0.0000	1.0000	73.54
45.5	1,205,258		0.0000	1.0000	73.54
46.5	1,196,483		0.0000	1.0000	73.54
47.5	1,196,338		0.0000	1.0000	73.54
48.5	1,097,149	28,151	0.0257	0.9743	73.54
49.5	1,017,491	67,043	0.0659	0.9341	71.65
50.5	950,448	6,606	0.0070	0.9930	66.93
51.5	943,842	12,962	0.0137	0.9863	66.47
52.5	930,880		0.0000	1.0000	65.55
53.5	925,924		0.0000	1.0000	65.55
54.5	925,610	477	0.0005	0.9995	65.55
55.5	766,270		0.0000	1.0000	65.52
56.5	728,303	1,003	0.0014	0.9986	65.52
57.5	323,638		0.0000	1.0000	65.43
58.5	323,638		0.0000	1.0000	65.43
59.5	323,143		0.0000	1.0000	65.43
60.5	323,143	5,082	0.0157	0.9843	65.43
61.5	318,061		0.0000	1.0000	64.40
62.5	318,061		0.0000	1.0000	64.40
63.5	312,123		0.0000	1.0000	64.40
64.5	11,784		0.0000	1.0000	64.40
65.5	11,759		0.0000	1.0000	64.40
66.5	7,090		0.0000	1.0000	64.40
67.5	2,815		0.0000	1.0000	64.40
68.5	2,815		0.0000	1.0000	64.40
69.5	1,653		0.0000	1.0000	64.40
70.5	1,653		0.0000	1.0000	64.40
71.5	1,653		0.0000	1.0000	64.40
72.5	1,653		0.0000	1.0000	64.40
73.5	1,653		0.0000	1.0000	64.40
74.5	1,653		0.0000	1.0000	64.40
75.5	1,653		0.0000	1.0000	64.40
76.5	11,499		0.0000	1.0000	64.40
77.5	11,499		0.0000	1.0000	64.40
78.5	11,499		0.0000	1.0000	64.40

THE POTOMAC EDISON COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2022 EXPERIENCE BAND 1997-2022

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	11,499		0.0000	1.0000	64.40
80.5	11,499		0.0000	1.0000	64.40
81.5	9,846		0.0000	1.0000	64.40
82.5	9,846		0.0000	1.0000	64.40
83.5	9,846		0.0000	1.0000	64.40
84.5	9,846		0.0000	1.0000	64.40
85.5	48,514		0.0000	1.0000	64.40
86.5	48,514		0.0000	1.0000	64.40
87.5	48,514		0.0000	1.0000	64.40
88.5	48,514		0.0000	1.0000	64.40
89.5	48,514		0.0000	1.0000	64.40
90.5	48,514		0.0000	1.0000	64.40
91.5	48,514		0.0000	1.0000	64.40
92.5	48,514		0.0000	1.0000	64.40
93.5	48,514		0.0000	1.0000	64.40
94.5	48,514		0.0000	1.0000	64.40
95.5	48,514		0.0000	1.0000	64.40
96.5	48,514		0.0000	1.0000	64.40
97.5	48,514		0.0000	1.0000	64.40
98.5	48,514		0.0000	1.0000	64.40
99.5	48,514		0.0000	1.0000	64.40
100.5	48,514		0.0000	1.0000	64.40
101.5	48,514		0.0000	1.0000	64.40
102.5	38,669		0.0000	1.0000	64.40
103.5	38,669		0.0000	1.0000	64.40
104.5	38,669		0.0000	1.0000	64.40
105.5	38,669		0.0000	1.0000	64.40
106.5	38,669		0.0000	1.0000	64.40
107.5	38,669		0.0000	1.0000	64.40
108.5	38,669		0.0000	1.0000	64.40
109.5	38,669		0.0000	1.0000	64.40
110.5	38,669		0.0000	1.0000	64.40
111.5					64.40

THE POTOMAC EDISON COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1911-2022 EXPERIENCE BAND 2013-2022

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	7,983,872		0.0000	1.0000	100.00
0.5	10,490,873	116,073	0.0111	0.9889	100.00
1.5	10,633,579		0.0000	1.0000	98.89
2.5	10,096,525	24,389	0.0024	0.9976	98.89
3.5	9,764,304		0.0000	1.0000	98.65
4.5	8,531,562		0.0000	1.0000	98.65
5.5	8,496,341	40,683	0.0048	0.9952	98.65
6.5	5,895,690		0.0000	1.0000	98.18
7.5	5,187,934	87,075	0.0168	0.9832	98.18
8.5	5,075,523	171,968	0.0339	0.9661	96.53
9.5	4,646,474	264	0.0001	0.9999	93.26
10.5	3,321,367		0.0000	1.0000	93.26
11.5	4,850,801	10,430	0.0022	0.9978	93.26
12.5	4,956,575	10,967	0.0022	0.9978	93.06
13.5	4,398,958	8,559	0.0019	0.9981	92.85
14.5	4,543,146		0.0000	1.0000	92.67
15.5	4,255,940		0.0000	1.0000	92.67
16.5	3,910,691		0.0000	1.0000	92.67
17.5	4,197,440	14,166	0.0034	0.9966	92.67
18.5	3,938,361		0.0000	1.0000	92.36
19.5	4,878,623	224	0.0000	1.0000	92.36
20.5	5,093,822	28,741	0.0056	0.9944	92.35
21.5	4,434,462	30,558	0.0069	0.9931	91.83
22.5	6,065,624		0.0000	1.0000	91.20
23.5	7,316,962	79,749	0.0109	0.9891	91.20
24.5	9,362,664	100,331	0.0107	0.9893	90.21
25.5	10,059,943	151,014	0.0150	0.9850	89.24
26.5	9,980,387	75,538	0.0076	0.9924	87.90
27.5	9,740,235	11,922	0.0012	0.9988	87.23
28.5	9,569,323	32,353	0.0034	0.9966	87.13
29.5	8,773,148	87,821	0.0100	0.9900	86.83
30.5	7,685,502		0.0000	1.0000	85.96
31.5	6,711,185	38,228	0.0057	0.9943	85.96
32.5	5,202,177		0.0000	1.0000	85.47
33.5	4,026,028	129,729	0.0322	0.9678	85.47
34.5	1,557,975		0.0000	1.0000	82.72
35.5	857,088	11,981	0.0140	0.9860	82.72
36.5	605,006		0.0000	1.0000	81.56
37.5	478,981		0.0000	1.0000	81.56
38.5	512,376		0.0000	1.0000	81.56

THE POTOMAC EDISON COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2022 EXPERIENCE BAND 2013-2022

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	732,485		0.0000	1.0000	81.56
40.5	720,916	6,322	0.0088	0.9912	81.56
41.5	655,822		0.0000	1.0000	80.85
42.5	410,964		0.0000	1.0000	80.85
43.5	394,272	160,052	0.4059	0.5941	80.85
44.5	213,397		0.0000	1.0000	48.03
45.5	354,475		0.0000	1.0000	48.03
46.5	399,048		0.0000	1.0000	48.03
47.5	874,353		0.0000	1.0000	48.03
48.5	775,165	28,151	0.0363	0.9637	48.03
49.5	696,001	67,043	0.0963	0.9037	46.28
50.5	628,958	6,606	0.0105	0.9895	41.83
51.5	622,352	12,962	0.0208	0.9792	41.39
52.5	609,390		0.0000	1.0000	40.52
53.5	610,372		0.0000	1.0000	40.52
54.5	915,480	477	0.0005	0.9995	40.52
55.5	754,511		0.0000	1.0000	40.50
56.5	721,213	1,003	0.0014	0.9986	40.50
57.5	320,822		0.0000	1.0000	40.45
58.5	320,822		0.0000	1.0000	40.45
59.5	321,489		0.0000	1.0000	40.45
60.5	321,489	5,082	0.0158	0.9842	40.45
61.5	316,407		0.0000	1.0000	39.81
62.5	316,407		0.0000	1.0000	39.81
63.5	310,469		0.0000	1.0000	39.81
64.5	10,130		0.0000	1.0000	39.81
65.5	10,106		0.0000	1.0000	39.81
66.5	5,437		0.0000	1.0000	39.81
67.5	1,162		0.0000	1.0000	39.81
68.5	1,162		0.0000	1.0000	39.81
69.5					39.81
70.5					
71.5	1,653		0.0000		
72.5	1,653		0.0000		
73.5	1,653		0.0000		
74.5	1,653		0.0000		
75.5	1,653		0.0000		
76.5	1,653		0.0000		
77.5	1,653		0.0000		
78.5	1,653		0.0000		

THE POTOMAC EDISON COMPANY

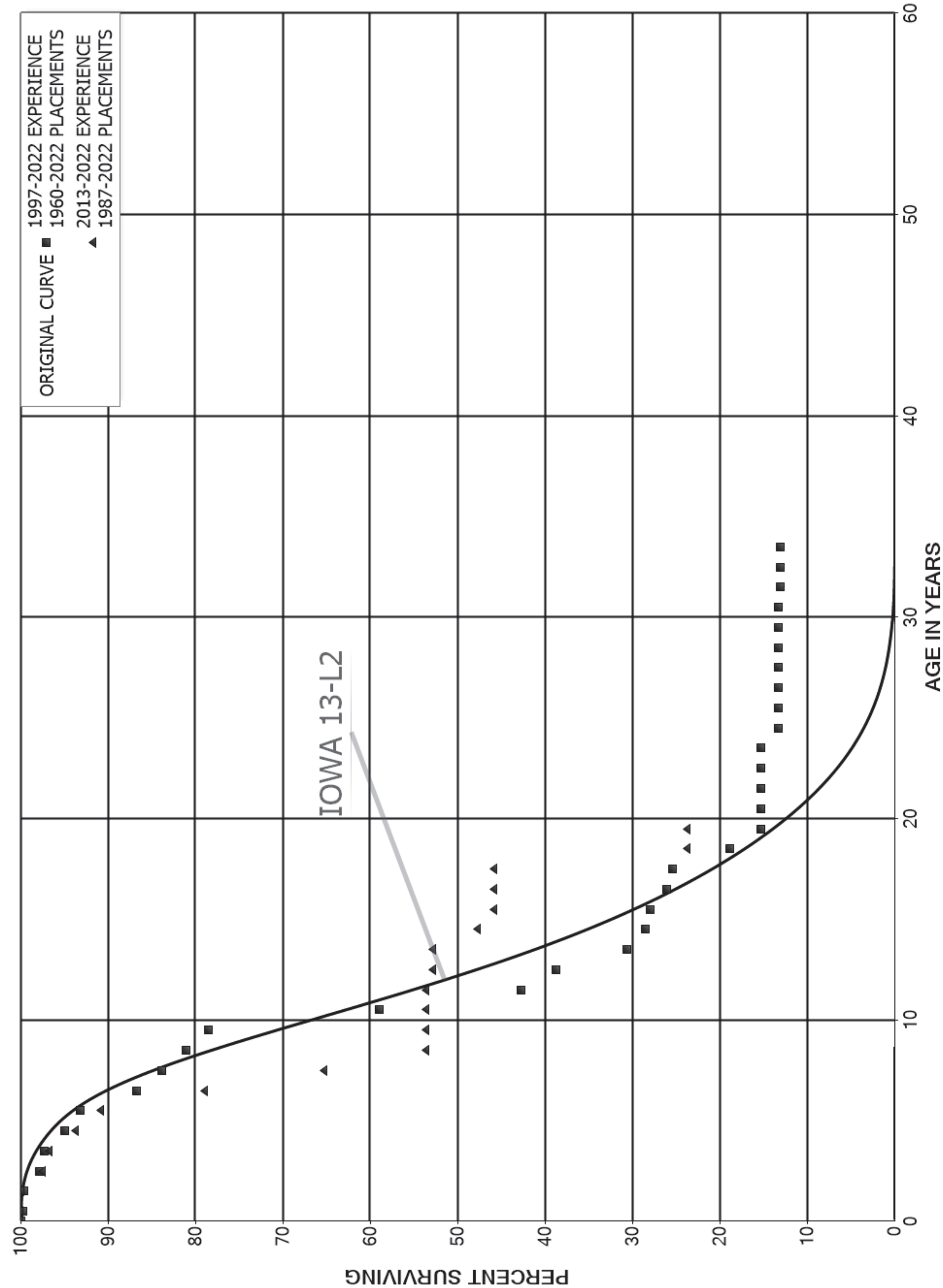
ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2022 EXPERIENCE BAND 2013-2022

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	1,653		0.0000		
80.5	1,653		0.0000		
81.5					
82.5					
83.5					
84.5					
85.5					
86.5					
87.5					
88.5					
89.5					
90.5					
91.5					
92.5	9,846		0.0000		
93.5	9,846		0.0000		
94.5	9,846		0.0000		
95.5	9,846		0.0000		
96.5	9,846		0.0000		
97.5	9,846		0.0000		
98.5	9,846		0.0000		
99.5	9,846		0.0000		
100.5	9,846		0.0000		
101.5	48,514		0.0000		
102.5	38,669		0.0000		
103.5	38,669		0.0000		
104.5	38,669		0.0000		
105.5	38,669		0.0000		
106.5	38,669		0.0000		
107.5	38,669		0.0000		
108.5	38,669		0.0000		
109.5	38,669		0.0000		
110.5	38,669		0.0000		
111.5					

THE POTOMAC EDISON COMPANY
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2022 EXPERIENCE BAND 1997-2022

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	5,360,684	15,366	0.0029	0.9971	100.00
0.5	5,219,519	6,778	0.0013	0.9987	99.71
1.5	4,793,357	85,233	0.0178	0.9822	99.58
2.5	4,222,690	22,843	0.0054	0.9946	97.81
3.5	3,038,895	73,120	0.0241	0.9759	97.28
4.5	2,778,549	52,054	0.0187	0.9813	94.94
5.5	2,396,294	164,838	0.0688	0.9312	93.16
6.5	5,387,898	180,935	0.0336	0.9664	86.76
7.5	5,565,597	184,274	0.0331	0.9669	83.84
8.5	5,044,205	157,219	0.0312	0.9688	81.07
9.5	5,229,961	1,307,797	0.2501	0.7499	78.54
10.5	3,791,297	1,038,778	0.2740	0.7260	58.90
11.5	2,752,519	263,370	0.0957	0.9043	42.76
12.5	2,489,149	522,031	0.2097	0.7903	38.67
13.5	1,924,420	127,472	0.0662	0.9338	30.56
14.5	1,796,947	39,825	0.0222	0.9778	28.54
15.5	1,757,122	113,756	0.0647	0.9353	27.90
16.5	1,643,366	47,597	0.0290	0.9710	26.10
17.5	1,487,915	379,925	0.2553	0.7447	25.34
18.5	1,099,493	206,594	0.1879	0.8121	18.87
19.5	545,596		0.0000	1.0000	15.32
20.5	545,596		0.0000	1.0000	15.32
21.5	545,596		0.0000	1.0000	15.32
22.5	545,596		0.0000	1.0000	15.32
23.5	545,596	71,294	0.1307	0.8693	15.32
24.5	474,302		0.0000	1.0000	13.32
25.5	475,681		0.0000	1.0000	13.32
26.5	475,681		0.0000	1.0000	13.32
27.5	475,681	280	0.0006	0.9994	13.32
28.5	475,401		0.0000	1.0000	13.31
29.5	483,689		0.0000	1.0000	13.31
30.5	533,108	8,288	0.0155	0.9845	13.31
31.5	486,234		0.0000	1.0000	13.11
32.5	297,674		0.0000	1.0000	13.11
33.5	68,979		0.0000	1.0000	13.11
34.5	68,979	8,608	0.1248	0.8752	13.11
35.5	1,451		0.0000	1.0000	11.47
36.5	10,506		0.0000	1.0000	11.47
37.5	10,506		0.0000	1.0000	11.47
38.5	10,506		0.0000	1.0000	11.47

THE POTOMAC EDISON COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2022 EXPERIENCE BAND 1997-2022

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	10,506		0.0000	1.0000	11.47
40.5	10,506	1,451	0.1381	0.8619	11.47
41.5	9,055		0.0000	1.0000	9.89
42.5	9,055		0.0000	1.0000	9.89
43.5	9,055		0.0000	1.0000	9.89
44.5	9,055		0.0000	1.0000	9.89
45.5	9,055	9,055	1.0000		9.89
46.5					

THE POTOMAC EDISON COMPANY

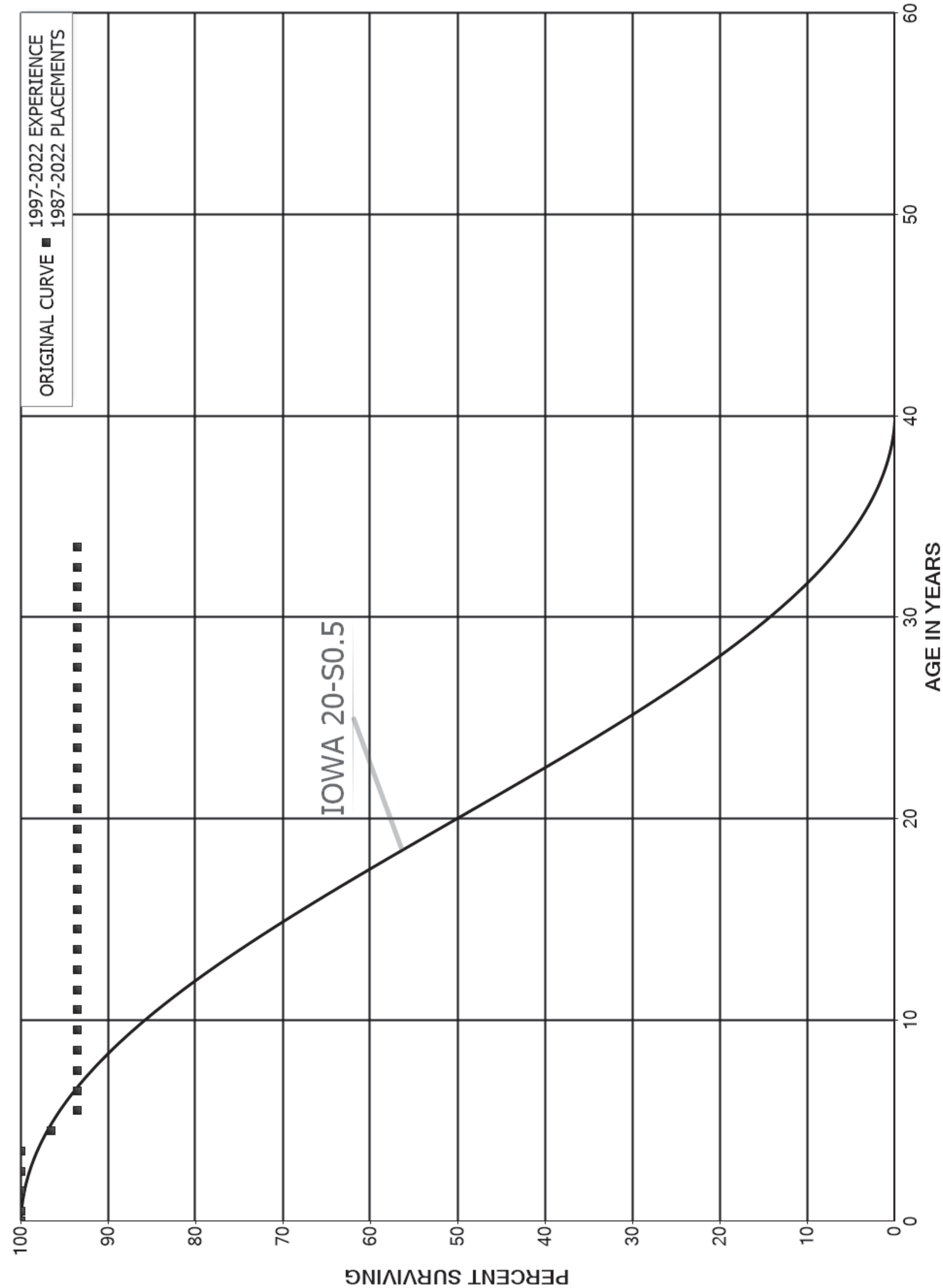
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1987-2022 EXPERIENCE BAND 2013-2022

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	3,911,443		0.0000	1.0000	100.00
0.5	3,916,512	6,778	0.0017	0.9983	100.00
1.5	3,490,350	85,233	0.0244	0.9756	99.83
2.5	2,919,683	22,843	0.0078	0.9922	97.39
3.5	1,778,586	55,946	0.0315	0.9685	96.63
4.5	1,703,349	52,054	0.0306	0.9694	93.59
5.5	1,258,716	164,838	0.1310	0.8690	90.73
6.5	1,042,376	180,935	0.1736	0.8264	78.85
7.5	1,034,580	184,274	0.1781	0.8219	65.16
8.5	469,240		0.0000	1.0000	53.55
9.5	1,105,912		0.0000	1.0000	53.55
10.5	975,045		0.0000	1.0000	53.55
11.5	975,045	15,366	0.0158	0.9842	53.55
12.5	959,679		0.0000	1.0000	52.71
13.5	916,981	88,316	0.0963	0.9037	52.71
14.5	828,665	32,318	0.0390	0.9610	47.63
15.5	796,347		0.0000	1.0000	45.78
16.5	796,347		0.0000	1.0000	45.78
17.5	688,492	332,693	0.4832	0.5168	45.78
18.5	347,302		0.0000	1.0000	23.66
19.5					23.66
20.5					
21.5	40,037		0.0000		
22.5	236,106		0.0000		
23.5	536,095	71,294	0.1330		
24.5	464,801		0.0000		
25.5	474,302		0.0000		
26.5	474,302		0.0000		
27.5	474,302		0.0000		
28.5	474,302		0.0000		
29.5	474,302		0.0000		
30.5	523,721		0.0000		
31.5	483,684		0.0000		
32.5	287,615		0.0000		
33.5	58,920		0.0000		
34.5	58,920		0.0000		
35.5					

THE POTOMAC EDISON COMPANY
ACCOUNT 396.00 POWER OPERATED EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



THE POTOMAC EDISON COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1987-2022 EXPERIENCE BAND 1997-2022

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	272,514		0.0000	1.0000	100.00
0.5	272,409		0.0000	1.0000	100.00
1.5	272,233		0.0000	1.0000	100.00
2.5	271,887		0.0000	1.0000	100.00
3.5	271,887	9,398	0.0346	0.9654	100.00
4.5	262,489	8,400	0.0320	0.9680	96.54
5.5	240,066		0.0000	1.0000	93.45
6.5	341,084		0.0000	1.0000	93.45
7.5	635,138		0.0000	1.0000	93.45
8.5	651,224		0.0000	1.0000	93.45
9.5	678,351		0.0000	1.0000	93.45
10.5	552,041		0.0000	1.0000	93.45
11.5	552,041		0.0000	1.0000	93.45
12.5	552,041		0.0000	1.0000	93.45
13.5	594,093		0.0000	1.0000	93.45
14.5	594,093		0.0000	1.0000	93.45
15.5	594,093		0.0000	1.0000	93.45
16.5	594,093		0.0000	1.0000	93.45
17.5	589,955		0.0000	1.0000	93.45
18.5	589,955		0.0000	1.0000	93.45
19.5	589,955		0.0000	1.0000	93.45
20.5	589,955		0.0000	1.0000	93.45
21.5	589,955		0.0000	1.0000	93.45
22.5	589,955		0.0000	1.0000	93.45
23.5	589,955		0.0000	1.0000	93.45
24.5	589,955		0.0000	1.0000	93.45
25.5	589,955		0.0000	1.0000	93.45
26.5	589,955		0.0000	1.0000	93.45
27.5	589,955		0.0000	1.0000	93.45
28.5	589,955		0.0000	1.0000	93.45
29.5	589,955		0.0000	1.0000	93.45
30.5	547,904		0.0000	1.0000	93.45
31.5	547,904		0.0000	1.0000	93.45
32.5	446,886		0.0000	1.0000	93.45
33.5	51,035		0.0000	1.0000	93.45
34.5	34,948		0.0000	1.0000	93.45
35.5					93.45

PART VIII. NET SALVAGE STATISTICS

THE POTOMAC EDISON COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2001	4,364	200	5		0	200-	5-
2002	5,450	4,416	81		0	4,416-	81-
2003	3,909	14,543	372	131	3	14,412-	369-
2004							
2005	2,247		0		0		0
2006	20,913	647	3		0	647-	3-
2007							
2008	9,471		0		0		0
2009							
2010	4,345	1,815	42		0	1,815-	42-
2011	8,283	1,976	24		0	1,976-	24-
2012							
2013							
2014							
2015							
2016							
2017	3,175	4,209	133		0	4,209-	133-
2018							
2019							
2020	210	1,253	596		0	1,253-	596-
2021	9,745	3,926	40		0	3,926-	40-
2022	7,859	13,569	173		0	13,569-	173-
TOTAL	79,970	46,553	58	131	0	46,422-	58-
THREE-YEAR MOVING AVERAGES							
01-03	4,574	6,386	140	44	1	6,343-	139-
02-04	3,120	6,320	203	44	1	6,276-	201-
03-05	2,052	4,848	236	44	2	4,804-	234-
04-06	7,720	216	3		0	216-	3-
05-07	7,720	216	3		0	216-	3-
06-08	10,128	216	2		0	216-	2-
07-09	3,157		0		0		0
08-10	4,605	605	13		0	605-	13-
09-11	4,209	1,264	30		0	1,264-	30-
10-12	4,209	1,264	30		0	1,264-	30-
11-13	2,761	659	24		0	659-	24-
12-14							
13-15							
14-16							
15-17	1,058	1,403	133		0	1,403-	133-
16-18	1,058	1,403	133		0	1,403-	133-

THE POTOMAC EDISON COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
17-19	1,058	1,403	133		0	1,403-	133-
18-20	70	418	596		0	418-	596-
19-21	3,318	1,726	52		0	1,726-	52-
20-22	5,938	6,249	105		0	6,249-	105-
FIVE-YEAR AVERAGE							
18-22	3,563	3,750	105		0	3,750-	105-

THE POTOMAC EDISON COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	41,728	12,216	29	15,584	37	3,368	8
2002	1,094,957	53,603	5	206,418	19	152,815	14
2003	88,946	27,694	31	234	0	27,461-	31-
2004	35,146	459	1	1,574	4	1,115	3
2005	127,357	8,570	7		0	8,570-	7-
2006	799,151	78,313	10		0	78,313-	10-
2007	53,883	5,423	10		0	5,423-	10-
2008	450,274	92,120	20		0	92,120-	20-
2009	110,985	31,072	28		0	31,072-	28-
2010	2,704,240	489,930	18	175,996	7	313,934-	12-
2011	179,022	17,030	10	28,209	16	11,179	6
2012	71,768	113	0		0	113-	0
2013	1,488,605	88,169	6	20,594	1	67,575-	5-
2014	247,645	43,006	17		0	43,006-	17-
2015	813,145	3,425	0		0	3,425-	0
2016	111,002	22,246	20		0	22,246-	20-
2017	202,496	23,345	12		0	23,345-	12-
2018	524,235	264,345	50	9,873	2	254,472-	49-
2019	105,707	88,578	84		0	88,578-	84-
2020	269,885	189,958	70		0	189,958-	70-
2021	592,773	358,874	61		0	358,874-	61-
2022	182,597	96,018	53		0	96,018-	53-
TOTAL	10,295,546	1,994,505	19	458,481	4	1,536,024-	15-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
01-03	408,544	31,171	8	74,078	18	42,907	11
02-04	406,350	27,252	7	69,408	17	42,156	10
03-05	83,816	12,241	15	603	1	11,639-	14-
04-06	320,551	29,114	9	525	0	28,589-	9-
05-07	326,797	30,769	9		0	30,769-	9-
06-08	434,436	58,619	13		0	58,619-	13-
07-09	205,048	42,872	21		0	42,872-	21-
08-10	1,088,500	204,374	19	58,665	5	145,709-	13-
09-11	998,082	179,344	18	68,068	7	111,276-	11-
10-12	985,010	169,024	17	68,068	7	100,956-	10-
11-13	579,798	35,104	6	16,268	3	18,836-	3-
12-14	602,672	43,763	7	6,865	1	36,898-	6-
13-15	849,798	44,867	5	6,865	1	38,002-	4-
14-16	390,597	22,892	6		0	22,892-	6-
15-17	375,548	16,338	4		0	16,338-	4-
16-18	279,244	103,312	37	3,291	1	100,021-	36-

THE POTOMAC EDISON COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
17-19	277,479	125,422	45	3,291	1	122,131-	44-
18-20	299,942	180,960	60	3,291	1	177,669-	59-
19-21	322,788	212,470	66		0	212,470-	66-
20-22	348,418	214,950	62		0	214,950-	62-
FIVE-YEAR AVERAGE							
18-22	335,039	199,554	60	1,975	1	197,580-	59-

THE POTOMAC EDISON COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	30,170	248,903	825	117,935	391	130,968-	434-
2002	68,004	211,868	312	8,980	13	202,888-	298-
2003	61,258	143,475	234	12,682	21	130,792-	214-
2004	97,844	569,284	582	92,997	95	476,288-	487-
2005	76,165	436,445	573	24,052	32	412,394-	541-
2006	89,746	369,083	411	886	1	368,197-	410-
2007	69,150	164,715	238	4,875	7	159,841-	231-
2008	144,554	1,653,481			0	1,653,481-	
2009	89,826	351,455	391	1,688	2	349,768-	389-
2010	65,106	1,064,950			0	1,064,950-	
2011	58,224	768,267		3	0	768,265-	
2012	41,785	52,606	126		0	52,606-	126-
2013	64,509	3,130,042		3,531	5	3,126,511-	
2014	46,585	1,269,772			0	1,269,772-	
2015	91,799	823,833	897		0	823,833-	897-
2016	155,864	417,199	268		0	417,199-	268-
2017	192,690	730,134	379		0	730,134-	379-
2018	182,093	1,026,978	564		0	1,026,978-	564-
2019	122,415	928,299	758		0	928,299-	758-
2020	116,245	1,068,283	919		0	1,068,283-	919-
2021	86,886	887,382			0	887,382-	
2022	75,880	461,420	608		0	461,420-	608-
TOTAL	2,026,798	16,777,877	828	267,627	13	16,510,250-	815-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
01-03	53,144	201,415	379	46,532	88	154,883-	291-
02-04	75,702	308,209	407	38,220	50	269,989-	357-
03-05	78,423	383,068	488	43,243	55	339,825-	433-
04-06	87,919	458,271	521	39,311	45	418,959-	477-
05-07	78,354	323,415	413	9,937	13	313,477-	400-
06-08	101,150	729,093	721	1,920	2	727,173-	719-
07-09	101,177	723,217	715	2,187	2	721,030-	713-
08-10	99,829	1,023,295		563	1	1,022,733-	
09-11	71,052	728,224		563	1	727,661-	
10-12	55,038	628,608		1	0	628,607-	
11-13	54,839	1,316,972		1,178	2	1,315,794-	
12-14	50,959	1,484,140		1,177	2	1,482,963-	
13-15	67,631	1,741,216		1,177	2	1,740,039-	
14-16	98,083	836,935	853		0	836,935-	853-
15-17	146,784	657,056	448		0	657,056-	448-
16-18	176,882	724,770	410		0	724,770-	410-

THE POTOMAC EDISON COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
17-19	165,733	895,137	540		0	895,137-	540-
18-20	140,251	1,007,853	719		0	1,007,853-	719-
19-21	108,515	961,322	886		0	961,322-	886-
20-22	93,004	805,695	866		0	805,695-	866-
FIVE-YEAR AVERAGE							
18-22	116,704	874,472	749		0	874,472-	749-

THE POTOMAC EDISON COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	214,180	14,690	7	199,287	93	184,597	86
2002	523,695	294,733	56	409,214	78	114,481	22
2003	378,701	411,724	109	300,700	79	111,024-	29-
2004	708,982	713,738	101	198,771	28	514,967-	73-
2005	683,397	343,858	50	20,670	3	323,187-	47-
2006	794,991	252,530	32	753,725	95	501,195	63
2007	437,427	179,029	41	2,182	0	176,847-	40-
2008	486,157	318,478	66		0	318,478-	66-
2009	260,088	137,019	53	581	0	136,437-	52-
2010	283,073	221,405	78	36,363	13	185,041-	65-
2011	629,929	262,514	42		0	262,514-	42-
2012	302,299	88,148	29		0	88,148-	29-
2013	894,225	5,054,736	565		0	5,054,736-	565-
2014	666,225	1,263,589	190		0	1,263,589-	190-
2015	881,656	1,338,463	152		0	1,338,463-	152-
2016	746,232	678,270	91		0	678,270-	91-
2017	893,682	1,100,714	123		0	1,100,714-	123-
2018	1,009,111	2,014,348	200		0	2,014,348-	200-
2019	944,065	1,954,781	207		0	1,954,781-	207-
2020	1,105,145	2,131,341	193		0	2,131,341-	193-
2021	856,660	1,451,644	169		0	1,451,644-	169-
2022	492,872	700,623	142		0	700,623-	142-
TOTAL	14,192,792	20,926,372	147	1,921,494	14	19,004,878-	134-

THREE-YEAR MOVING AVERAGES

01-03	372,192	240,382	65	303,067	81	62,685	17
02-04	537,126	473,398	88	302,895	56	170,503-	32-
03-05	590,360	489,773	83	173,381	29	316,393-	54-
04-06	729,124	436,709	60	324,389	44	112,320-	15-
05-07	638,605	258,472	40	258,859	41	387	0
06-08	572,858	250,012	44	251,969	44	1,957	0
07-09	394,557	211,509	54	921	0	210,587-	53-
08-10	343,106	225,634	66	12,315	4	213,319-	62-
09-11	391,030	206,979	53	12,315	3	194,664-	50-
10-12	405,100	190,689	47	12,121	3	178,568-	44-
11-13	608,818	1,801,799	296		0	1,801,799-	296-
12-14	620,916	2,135,491	344		0	2,135,491-	344-
13-15	814,036	2,552,262	314		0	2,552,262-	314-
14-16	764,704	1,093,441	143		0	1,093,441-	143-
15-17	840,523	1,039,149	124		0	1,039,149-	124-
16-18	883,008	1,264,444	143		0	1,264,444-	143-

THE POTOMAC EDISON COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
17-19	948,953	1,689,948	178		0	1,689,948-	178-
18-20	1,019,440	2,033,490	199		0	2,033,490-	199-
19-21	968,623	1,845,922	191		0	1,845,922-	191-
20-22	818,225	1,427,869	175		0	1,427,869-	175-
FIVE-YEAR AVERAGE							
18-22	881,571	1,650,547	187		0	1,650,547-	187-

THE POTOMAC EDISON COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	39,700	5,630	14	5,883	15	253	1
2002	62,209	5,625	9	3,384	5	2,241-	4-
2003	29,811	9,329	31	5,520	19	3,809-	13-
2004	42,032	106,697	254	19,358	46	87,339-	208-
2005	42,441	42,277	100	5,253	12	37,023-	87-
2006	48,121	1,478	3		0	1,478-	3-
2007	34,117	16,948	50	195	1	16,753-	49-
2008	46,845	9,627	21		0	9,627-	21-
2009	35,412	16,239	46	218	1	16,021-	45-
2010	24,222	8,226	34		0	8,226-	34-
2011	22,129	22,294	101		0	22,294-	101-
2012	14,137	32	0		0	32-	0
2013	8,693	16,619	191		0	16,619-	191-
2014	35,996	208,086	578		0	208,086-	578-
2015	15,641	142,134	909		0	142,134-	909-
2016	73,247	33,505	46		0	33,505-	46-
2017	9,432	82,644	876		0	82,644-	876-
2018	7,904	2,397	30		0	2,397-	30-
2019	4,618	15,185	329		0	15,185-	329-
2020	693	8,897			0	8,897-	
2021		5,510				5,510-	
2022	6,291	172	3		0	172-	3-
TOTAL	603,691	759,549	126	39,811	7	719,738-	119-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
01-03	43,907	6,861	16	4,929	11	1,932-	4-
02-04	44,684	40,550	91	9,421	21	31,130-	70-
03-05	38,095	52,768	139	10,044	26	42,724-	112-
04-06	44,198	50,151	113	8,204	19	41,947-	95-
05-07	41,560	20,234	49	1,816	4	18,418-	44-
06-08	43,028	9,351	22	65	0	9,286-	22-
07-09	38,792	14,271	37	138	0	14,134-	36-
08-10	35,493	11,364	32	73	0	11,291-	32-
09-11	27,255	15,586	57	73	0	15,513-	57-
10-12	20,163	10,184	51		0	10,184-	51-
11-13	14,986	12,982	87		0	12,982-	87-
12-14	19,609	74,912	382		0	74,912-	382-
13-15	20,110	122,280	608		0	122,280-	608-
14-16	41,628	127,908	307		0	127,908-	307-
15-17	32,773	86,094	263		0	86,094-	263-
16-18	30,194	39,515	131		0	39,515-	131-

THE POTOMAC EDISON COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
17-19	7,318	33,409	457		0	33,409-	457-
18-20	4,405	8,826	200		0	8,826-	200-
19-21	1,770	9,864	557		0	9,864-	557-
20-22	2,328	4,859	209		0	4,859-	209-
FIVE-YEAR AVERAGE							
18-22	3,901	6,432	165		0	6,432-	165-

THE POTOMAC EDISON COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	53,986	68,709	127	10,540	20	58,168-	108-
2002	373,964	2,834	1	351	0	2,483-	1-
2003	220,217	33,846	15	25,332	12	8,514-	4-
2004	494,594	500,099	101	78,739	16	421,360-	85-
2005	484,632	199,688	41	9,507	2	190,181-	39-
2006	448,213	51,572	12	149	0	51,423-	11-
2007	241,313	249,689	103	573	0	249,115-	103-
2008	546,516	188,061	34		0	188,061-	34-
2009	402,516	138,035	34	122	0	137,914-	34-
2010	308,993	176,278	57		0	176,278-	57-
2011	409,224	314,064	77	96,926-	24-	410,990-	100-
2012	364,370	47,507	13		0	47,507-	13-
2013	2,489,610	1,221,941	49		0	1,221,941-	49-
2014	1,627,142	911,944	56		0	911,944-	56-
2015	3,074,515	792,308	26		0	792,308-	26-
2016	1,813,125	613,650	34		0	613,650-	34-
2017	1,276,644	631,723	49		0	631,723-	49-
2018	1,270,270	1,301,056	102		0	1,301,056-	102-
2019	4,118,520	2,953,803	72		0	2,953,803-	72-
2020	3,806,762	2,563,284	67		0	2,563,284-	67-
2021	3,328,915	1,955,014	59		0	1,955,014-	59-
2022	2,085,014	870,858	42		0	870,858-	42-
TOTAL	29,239,056	15,785,964	54	28,388	0	15,757,576-	54-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
01-03	216,056	35,130	16	12,075	6	23,055-	11-
02-04	362,925	178,926	49	34,807	10	144,119-	40-
03-05	399,814	244,544	61	37,859	9	206,685-	52-
04-06	475,813	250,453	53	29,465	6	220,988-	46-
05-07	391,386	166,983	43	3,410	1	163,573-	42-
06-08	412,014	163,107	40	241	0	162,866-	40-
07-09	396,782	191,928	48	232	0	191,697-	48-
08-10	419,342	167,458	40	41	0	167,418-	40-
09-11	373,577	209,459	56	32,268-	9-	241,727-	65-
10-12	360,862	179,283	50	32,309-	9-	211,592-	59-
11-13	1,087,735	527,837	49	32,309-	3-	560,146-	51-
12-14	1,493,707	727,131	49		0	727,131-	49-
13-15	2,397,089	975,398	41		0	975,398-	41-
14-16	2,171,594	772,634	36		0	772,634-	36-
15-17	2,054,761	679,227	33		0	679,227-	33-
16-18	1,453,346	848,810	58		0	848,810-	58-

THE POTOMAC EDISON COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
17-19	2,221,811	1,628,861	73		0	1,628,861-	73-
18-20	3,065,184	2,272,715	74		0	2,272,715-	74-
19-21	3,751,399	2,490,701	66		0	2,490,701-	66-
20-22	3,073,564	1,796,385	58		0	1,796,385-	58-
FIVE-YEAR AVERAGE							
18-22	2,921,896	1,928,803	66		0	1,928,803-	66-

THE POTOMAC EDISON COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	441,813	227,681	52	329,394	75	101,713	23
2002	896,475	162,276	18	21,366	2	140,910-	16-
2003	566,476	269,683	48	53,561	9	216,122-	38-
2004	852,125	778,297	91	112,640	13	665,657-	78-
2005	732,780	410,953	56	16,340	2	394,613-	54-
2006	821,384	233,318	28	2,817	0	230,501-	28-
2007	658,806	134,828	20	994	0	133,834-	20-
2008	779,212	544,513	70		0	544,513-	70-
2009	642,481	266,886	42	382	0	266,504-	41-
2010	571,425	502,814	88		0	502,814-	88-
2011	724,210	806,369	111		0	806,369-	111-
2012	525,370	56,086	11		0	56,086-	11-
2013	2,659,290	1,231,840	46		0	1,231,840-	46-
2014	1,245,625	900,580	72		0	900,580-	72-
2015	1,702,389	475,277	28		0	475,277-	28-
2016	1,624,413	265,192	16		0	265,192-	16-
2017	1,501,969	365,767	24		0	365,767-	24-
2018	2,057,459	572,830	28		0	572,830-	28-
2019	2,429,685	707,884	29		0	707,884-	29-
2020	2,368,606	752,109	32		0	752,109-	32-
2021	2,099,679	590,687	28		0	590,687-	28-
2022	974,274	252,587	26		0	252,587-	26-
TOTAL	26,875,948	10,508,457	39	537,494	2	9,970,963-	37-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
01-03	634,921	219,880	35	134,774	21	85,106-	13-
02-04	771,692	403,419	52	62,522	8	340,896-	44-
03-05	717,127	486,311	68	60,847	8	425,464-	59-
04-06	802,096	474,189	59	43,932	5	430,257-	54-
05-07	737,657	259,700	35	6,717	1	252,983-	34-
06-08	753,134	304,220	40	1,270	0	302,949-	40-
07-09	693,500	315,409	45	458	0	314,950-	45-
08-10	664,373	438,071	66	127	0	437,944-	66-
09-11	646,039	525,356	81	127	0	525,229-	81-
10-12	607,002	455,090	75		0	455,090-	75-
11-13	1,302,957	698,098	54		0	698,098-	54-
12-14	1,476,762	729,502	49		0	729,502-	49-
13-15	1,869,102	869,232	47		0	869,232-	47-
14-16	1,524,142	547,016	36		0	547,016-	36-
15-17	1,609,590	368,745	23		0	368,745-	23-
16-18	1,727,947	401,263	23		0	401,263-	23-

THE POTOMAC EDISON COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
17-19	1,996,371	548,827	27		0	548,827-	27-
18-20	2,285,250	677,608	30		0	677,608-	30-
19-21	2,299,324	683,560	30		0	683,560-	30-
20-22	1,814,187	531,794	29		0	531,794-	29-
FIVE-YEAR AVERAGE							
18-22	1,985,941	575,220	29		0	575,220-	29-

THE POTOMAC EDISON COMPANY

ACCOUNT 369.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	26,339	18,141	69	36,286	138	18,144	69
2002	32,925	3,270	10		0	3,270-	10-
2003	31,522	24,980	79	7,558	24	17,423-	55-
2004	53,789	221,997	413	45,346	84	176,651-	328-
2005	32,423	187,337	578	33,545	103	153,792-	474-
2006	57,748	8,015	14	1,051	2	6,964-	12-
2007	14,702	79,065	538	1,405	10	77,660-	528-
2008	16,449	52,808	321		0	52,808-	321-
2009	11,486	50,880	443	531	5	50,349-	438-
2010	19,669	39,136	199		0	39,136-	199-
2011	13,271	109,864	828		0	109,864-	828-
2012	20,595	14,172	69		0	14,172-	69-
2013	50,234	104,056	207		0	104,056-	207-
2014	36,645	123,391	337		0	123,391-	337-
2015	36,500	114,902	315		0	114,902-	315-
2016	36,457	106,095	291		0	106,095-	291-
2017	136,375	404,689	297		0	404,689-	297-
2018	31,824	117,230	368		0	117,230-	368-
2019	20,246	193,840	957		0	193,840-	957-
2020	47,351	239,994	507		0	239,994-	507-
2021	9,161	199,219			0	199,219-	
2022	55,746	144,374	259		0	144,374-	259-
TOTAL	791,457	2,557,459	323	125,722	16	2,431,737-	307-

THREE-YEAR MOVING AVERAGES

01-03	30,262	15,464	51	14,614	48	850-	3-
02-04	39,412	83,416	212	17,634	45	65,781-	167-
03-05	39,245	144,772	369	28,816	73	115,955-	295-
04-06	47,987	139,116	290	26,648	56	112,469-	234-
05-07	34,957	91,472	262	12,001	34	79,472-	227-
06-08	29,633	46,629	157	819	3	45,810-	155-
07-09	14,212	60,918	429	645	5	60,272-	424-
08-10	15,868	47,608	300	177	1	47,431-	299-
09-11	14,809	66,627	450	177	1	66,450-	449-
10-12	17,845	54,391	305		0	54,391-	305-
11-13	28,033	76,031	271		0	76,031-	271-
12-14	35,825	80,540	225		0	80,540-	225-
13-15	41,126	114,116	277		0	114,116-	277-
14-16	36,534	114,796	314		0	114,796-	314-
15-17	69,778	208,562	299		0	208,562-	299-
16-18	68,219	209,338	307		0	209,338-	307-

THE POTOMAC EDISON COMPANY

ACCOUNT 369.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
17-19	62,815	238,587	380		0	238,587-	380-
18-20	33,140	183,688	554		0	183,688-	554-
19-21	25,586	211,018	825		0	211,018-	825-
20-22	37,419	194,529	520		0	194,529-	520-
FIVE-YEAR AVERAGE							
18-22	32,866	178,932	544		0	178,932-	544-

THE POTOMAC EDISON COMPANY

ACCOUNT 370.00 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	417,990	34,975	8	16,956	4	18,019-	4-
2002	42,212	1,403	3	3,171	8	1,768	4
2003	36,804	6,972	19	2,318	6	4,654-	13-
2004	106,479	40,480	38	12,607	12	27,873-	26-
2005	57,516	75,980	132	1,761	3	74,219-	129-
2006	95,704	1,793-	2-	339	0	2,132	2
2007	79,864	58,890	74	120	0	58,770-	74-
2008	190,465	78,375	41		0	78,375-	41-
2009	167,901	114,185	68		0	114,185-	68-
2010	159,025	231,792	146		0	231,792-	146-
2011	141,361	223,395	158		0	223,395-	158-
2012	250,242	107,596	43		0	107,596-	43-
2013	797,927	724,195	91		0	724,195-	91-
2014	104,719	182,830	175		0	182,830-	175-
2015	376,096	772,895	206		0	772,895-	206-
2016	580,856	327,956	56		0	327,956-	56-
2017	612,348	976,838	160		0	976,838-	160-
2018	565,051	785,885	139		0	785,885-	139-
2019	541,293	333,590	62		0	333,590-	62-
2020	627,528	249,195	40		0	249,195-	40-
2021	548,818	603,110	110		0	603,110-	110-
2022	299,481	46,010	15		0	46,010-	15-
TOTAL	6,799,681	5,974,754	88	37,272	1	5,937,483-	87-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
01-03	165,669	14,450	9	7,482	5	6,968-	4-
02-04	61,832	16,285	26	6,032	10	10,253-	17-
03-05	66,933	41,144	61	5,562	8	35,582-	53-
04-06	86,566	38,222	44	4,902	6	33,320-	38-
05-07	77,695	44,359	57	740	1	43,619-	56-
06-08	122,011	45,158	37	153	0	45,004-	37-
07-09	146,077	83,817	57	40	0	83,777-	57-
08-10	172,464	141,451	82		0	141,451-	82-
09-11	156,096	189,791	122		0	189,791-	122-
10-12	183,543	187,594	102		0	187,594-	102-
11-13	396,510	351,729	89		0	351,729-	89-
12-14	384,296	338,207	88		0	338,207-	88-
13-15	426,248	559,973	131		0	559,973-	131-
14-16	353,890	427,894	121		0	427,894-	121-
15-17	523,100	692,563	132		0	692,563-	132-
16-18	586,085	696,893	119		0	696,893-	119-

THE POTOMAC EDISON COMPANY

ACCOUNT 370.00 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
17-19	572,897	698,771	122		0	698,771-	122-
18-20	577,957	456,223	79		0	456,223-	79-
19-21	572,546	395,298	69		0	395,298-	69-
20-22	491,942	299,439	61		0	299,439-	61-
FIVE-YEAR AVERAGE							
18-22	516,434	403,558	78		0	403,558-	78-

THE POTOMAC EDISON COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2012		4,159				4,159-	
2013	29,004	65,226	225		0	65,226-	225-
2014	17,563	16,806	96		0	16,806-	96-
2015	117,291	20,987	18		0	20,987-	18-
2016	7,678	6,382	83		0	6,382-	83-
2017	2,954	3,928	133		0	3,928-	133-
2018	3,880	3,154	81		0	3,154-	81-
2019	1,718	6,545	381		0	6,545-	381-
2020	2,049	8,339	407		0	8,339-	407-
2021	765	2,869	375		0	2,869-	375-
2022	1,389	2,721	196		0	2,721-	196-
TOTAL	184,291	141,116	77		0	141,116-	77-
THREE-YEAR MOVING AVERAGES							
12-14	15,522	28,730	185		0	28,730-	185-
13-15	54,619	34,340	63		0	34,340-	63-
14-16	47,511	14,725	31		0	14,725-	31-
15-17	42,641	10,432	24		0	10,432-	24-
16-18	4,837	4,488	93		0	4,488-	93-
17-19	2,851	4,542	159		0	4,542-	159-
18-20	2,549	6,013	236		0	6,013-	236-
19-21	1,511	5,918	392		0	5,918-	392-
20-22	1,401	4,643	331		0	4,643-	331-
FIVE-YEAR AVERAGE							
18-22	1,960	4,726	241		0	4,726-	241-

THE POTOMAC EDISON COMPANY

ACCOUNTS 373.10 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	77,115	244,165	317	60,641	79	183,524-	238-
2002	119,379	12,781	11		0	12,781-	11-
2003	165,947	22,072	13	7,416	4	14,656-	9-
2004	216,385	137,503	64	23,380	11	114,123-	53-
2005	140,133	23,036	16	523	0	22,513-	16-
2006	160,678	1,384	1		0	1,384-	1-
2007	150,269	30,171	20	13	0	30,157-	20-
2008	245,263	436,000	178		0	436,000-	178-
2009	311,990	165,971	53		0	165,971-	53-
2010	494,234	370,112	75		0	370,112-	75-
2011	211,666	528,626	250	8,068	4	520,558-	246-
2012	134,829	16,292	12		0	16,292-	12-
2013	128,420	317,601	247		0	317,601-	247-
2014	42,701	44,347	104		0	44,347-	104-
2015	100,094	87,612	88		0	87,612-	88-
2016	156,605	59,517	38		0	59,517-	38-
2017	136,545	71,016	52		0	71,016-	52-
2018	164,007	93,999	57		0	93,999-	57-
2019	141,598	111,979	79		0	111,979-	79-
2020	197,640	101,537	51		0	101,537-	51-
2021	170,877	124,200	73		0	124,200-	73-
2022	90,619	99,248	110		0	99,248-	110-
TOTAL	3,756,995	3,099,168	82	100,042	3	2,999,126-	80-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
01-03	120,814	93,006	77	22,686	19	70,320-	58-
02-04	167,237	57,452	34	10,265	6	47,187-	28-
03-05	174,155	60,870	35	10,440	6	50,431-	29-
04-06	172,399	53,974	31	7,968	5	46,007-	27-
05-07	150,360	18,197	12	179	0	18,018-	12-
06-08	185,403	155,852	84	4	0	155,847-	84-
07-09	235,841	210,714	89	4	0	210,710-	89-
08-10	350,496	324,028	92		0	324,028-	92-
09-11	339,297	354,903	105	2,689	1	352,214-	104-
10-12	280,243	305,010	109	2,689	1	302,321-	108-
11-13	158,305	287,506	182	2,689	2	284,817-	180-
12-14	101,983	126,080	124		0	126,080-	124-
13-15	90,405	149,853	166		0	149,853-	166-
14-16	99,800	63,825	64		0	63,825-	64-
15-17	131,081	72,715	55		0	72,715-	55-
16-18	152,386	74,844	49		0	74,844-	49-

THE POTOMAC EDISON COMPANY

ACCOUNTS 373.10 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
17-19	147,383	92,331	63		0	92,331-	63-
18-20	167,748	102,505	61		0	102,505-	61-
19-21	170,038	112,572	66		0	112,572-	66-
20-22	153,046	108,328	71		0	108,328-	71-
FIVE-YEAR AVERAGE							
18-22	152,948	106,192	69		0	106,192-	69-

THE POTOMAC EDISON COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2006	454,028		0		0		0
2007	26,885	4,703	17		0	4,703-	17-
2008							
2009	96,974	32,000	33	19,479	20	12,521-	13-
2010	40,699		0		0		0
2011							
2012							
2013	1,023,837		0		0		0
2014							
2015	270,256	43,954	16		0	43,954-	16-
2016	11,922	4,813	40		0	4,813-	40-
2017	332,755	156,954	47		0	156,954-	47-
2018	95,836	9,092	9		0	9,092-	9-
2019	157,597	14,014	9		0	14,014-	9-
2020	88,161	16,849	19		0	16,849-	19-
2021	240,425	97,785	41		0	97,785-	41-
2022	70,597	7,365	10		0	7,365-	10-
TOTAL	2,909,970	387,529	13	19,479	1	368,050-	13-
THREE-YEAR MOVING AVERAGES							
06-08	160,304	1,568	1		0	1,568-	1-
07-09	41,286	12,234	30	6,493	16	5,741-	14-
08-10	45,891	10,667	23	6,493	14	4,174-	9-
09-11	45,891	10,667	23	6,493	14	4,174-	9-
10-12	13,566		0		0		0
11-13	341,279		0		0		0
12-14	341,279		0		0		0
13-15	431,364	14,651	3		0	14,651-	3-
14-16	94,059	16,256	17		0	16,256-	17-
15-17	204,978	68,574	33		0	68,574-	33-
16-18	146,838	56,953	39		0	56,953-	39-
17-19	195,396	60,020	31		0	60,020-	31-
18-20	113,864	13,319	12		0	13,319-	12-
19-21	162,061	42,883	26		0	42,883-	26-
20-22	133,061	40,666	31		0	40,666-	31-
FIVE-YEAR AVERAGE							
18-22	130,523	29,021	22		0	29,021-	22-

THE POTOMAC EDISON COMPANY

ACCOUNT 392.00 TRANSPORATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	736,499		0	161,801	22	161,801	22
2002	176,870		0	76,365	43	76,365	43
2003	407,402		0		0		0
2004		41		43,167		43,126	
2005	15,366		0	18,467	120	18,467	120
2006	180,465		0	17,932	10	17,932	10
2007							
2008	83,462		0	869	1	869	1
2009	187,538		0		0		0
2010		20,500-		65,630		86,130	
2011							
2012				5,834		5,834	
2013	224,530		0		0		0
2014	6,778		0		0		0
2015	9,126		0	60,066	658	60,066	658
2016							
2017	55,448		0	65,872	119	65,872	119
2018							
2019	194,819		0		0		0
2020	216,243		0		0		0
2021	585,946		0		0		0
2022							
TOTAL	3,080,489	20,459-	1-	516,003	17	536,462	17

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
01-03	440,257		0	79,389	18	79,389	18
02-04	194,757	14	0	39,844	20	39,830	20
03-05	140,923	14	0	20,544	15	20,531	15
04-06	65,277	14	0	26,522	41	26,508	41
05-07	65,277		0	12,133	19	12,133	19
06-08	87,976		0	6,267	7	6,267	7
07-09	90,333		0	290	0	290	0
08-10	90,333	6,833-	8-	22,166	25	29,000	32
09-11	62,513	6,833-	11-	21,877	35	28,710	46
10-12		6,833-		23,822		30,655	
11-13	74,843		0	1,945	3	1,945	3
12-14	77,102		0	1,945	3	1,945	3
13-15	80,144		0	20,022	25	20,022	25
14-16	5,301		0	20,022	378	20,022	378
15-17	21,525		0	41,979	195	41,979	195
16-18	18,483		0	21,957	119	21,957	119

THE POTOMAC EDISON COMPANY

ACCOUNT 392.00 TRANSPORATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
17-19	83,422		0	21,957	26	21,957	26
18-20	137,021		0		0		0
19-21	332,336		0		0		0
20-22	267,396		0		0		0
FIVE-YEAR AVERAGE							
18-22	199,402		0		0		0

THE POTOMAC EDISON COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2006	8,400		0		0		0
2007	9,398		0		0		0
2008		680		17,884		17,204	
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
TOTAL	17,797	680	4	17,884	100	17,204	97
THREE-YEAR MOVING AVERAGES							
06-08	5,932	227	4	5,961	100	5,735	97
07-09	3,132	227	7	5,961	190	5,735	183
08-10		227		5,961		5,735	
09-11							
10-12							
11-13							
12-14							
13-15							
14-16							
15-17							
16-18							
17-19							
18-20							
19-21							
20-22							
FIVE-YEAR AVERAGE							
18-22							

PART IX. DETAILED DEPRECIATION CALCULATIONS

THE POTOMAC EDISON COMPANY

ACCOUNT 303.00 MISCELLANEOUS INTANGIBLE PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 7-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	4,065,813.52	4,065,814	4,065,814			
2013	3,319,463.95	3,319,464	3,319,464			
2014	999,423.57	999,424	999,424			
2015	1,146,068.99	1,146,069	1,146,069			
2016	1,436,850.15	1,231,582	1,394,690	42,160	1.00	42,160
2017	1,627,201.29	1,162,294	1,316,226	310,975	2.00	155,488
2018	5,255,955.54	3,003,411	3,401,177	1,854,779	3.00	618,260
2019	3,362,807.35	1,441,198	1,632,067	1,730,740	4.00	432,685
2020	2,695,896.65	770,245	872,255	1,823,642	5.00	364,728
2021	995,109.46	142,161	160,988	834,121	6.00	139,020
2022	614,340.14	21,938	24,844	589,496	6.75	87,333
	25,518,930.61	17,303,600	18,333,018	7,185,913		1,839,674

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.9   7.21

THE POTOMAC EDISON COMPANY

ACCOUNT 360.20 LAND AND LAND RIGHTS - EASEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 75-R3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1945	127,639.47	103,439	107,749	19,890	14.22	1,399
1953	258,623.23	195,933	204,097	54,526	18.18	2,999
1954	31,794.44	23,854	24,848	6,946	18.73	371
1955	45,324.46	33,667	35,070	10,254	19.29	532
1956	19,528.59	14,355	14,953	4,576	19.87	230
1957	17,168.80	12,485	13,005	4,164	20.46	204
1958	76,754.87	55,202	57,502	19,253	21.06	914
1959	52,861.82	37,588	39,154	13,708	21.67	633
1960	9,919.21	6,971	7,261	2,658	22.29	119
1961	79,869.77	55,462	57,773	22,097	22.92	964
1962	47,576.87	32,632	33,992	13,585	23.56	577
1963	55,071.15	37,287	38,841	16,230	24.22	670
1964	38,812.46	25,937	27,018	11,794	24.88	474
1965	32,530.21	21,448	22,342	10,188	25.55	399
1966	48,367.86	31,445	32,755	15,613	26.24	595
1967	80,671.70	51,705	53,859	26,813	26.93	996
1968	76,766.98	48,486	50,506	26,261	27.63	950
1969	29,966.67	18,643	19,420	10,547	28.34	372
1970	68,076.58	41,699	43,437	24,640	29.06	848
1971	65,784.35	39,663	41,316	24,468	29.78	822
1972	239,923.05	142,291	148,220	91,703	30.52	3,005
1973	26,447.98	15,424	16,067	10,381	31.26	332
1974	34,581.39	19,822	20,648	13,933	32.01	435
1975	20,556.27	11,575	12,057	8,499	32.77	259
1976	22,446.30	12,408	12,925	9,521	33.54	284
1977	31,589.74	17,138	17,852	13,738	34.31	400
1978	30,131.51	16,034	16,702	13,430	35.09	383
1979	15,591.98	8,133	8,472	7,120	35.88	198
1980	80,977.96	41,374	43,098	37,880	36.68	1,033
1981	133,961.66	67,017	69,809	64,153	37.48	1,712
1982	85,874.00	42,033	43,784	42,090	38.29	1,099
1983	39,101.68	18,711	19,491	19,611	39.11	501
1984	28,701.03	13,421	13,980	14,721	39.93	369
1985	39,963.23	18,244	19,004	20,959	40.76	514
1986	42,954.73	19,129	19,926	23,029	41.60	554
1987	19,810.30	8,600	8,958	10,852	42.44	256
1988	23,699.91	10,020	10,438	13,262	43.29	306
1989	39,871.50	16,406	17,090	22,782	44.14	516
1990	66,872.81	26,740	27,854	39,019	45.01	867
1991	123,777.04	48,075	50,078	73,699	45.87	1,607
1992	53,917.66	20,309	21,155	32,763	46.75	701
1993	19,617.26	7,162	7,460	12,157	47.62	255
1994	22,697.40	8,017	8,351	14,346	48.51	296

THE POTOMAC EDISON COMPANY

ACCOUNT 360.20 LAND AND LAND RIGHTS - EASEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 75-R3						
NET SALVAGE PERCENT.. 0						
1995	695,096.71	237,257	247,143	447,954	49.40	9,068
1996	101,055.79	33,281	34,668	66,388	50.30	1,320
1997	172,774.99	54,827	57,112	115,663	51.20	2,259
1998	271,304.17	82,837	86,289	185,015	52.10	3,551
1999	10,542.15	3,091	3,220	7,322	53.01	138
2000	144,263.08	40,528	42,217	102,046	53.93	1,892
2001	17,573.59	4,721	4,918	12,656	54.85	231
2003	138,199.40	33,703	35,107	103,092	56.71	1,818
2004	39,388.75	9,117	9,497	29,892	57.64	519
2005	599,503.49	131,249	136,718	462,785	58.58	7,900
2007	1,040,277.74	201,679	210,082	830,196	60.46	13,731
2008	1,055,295.22	191,219	199,187	856,108	61.41	13,941
2010	1,685,990.40	262,559	273,499	1,412,491	63.32	22,307
2011	1,032,285.12	147,545	153,693	878,592	64.28	13,668
2012	290,672.10	37,825	39,401	251,271	65.24	3,851
2018	1,198,711.03	62,812	65,429	1,133,282	71.07	15,946
2020	1.00		0	1	73.03	
	10,999,110.61	3,030,234	3,156,497	7,842,614		143,090

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 54.8 1.30

THE POTOMAC EDISON COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 65-S4
NET SALVAGE PERCENT.. -20

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1950	2,283.85	2,453	2,741			
1952	8,202.64	8,721	9,843			
1953	7,122.83	7,532	8,547			
1954	1,574.04	1,655	1,889			
1955	2,607.32	2,726	3,129			
1956	495.06	514	594			
1957	79,494.63	82,053	95,394			
1958	5,159.30	5,289	6,191			
1959	6,687.89	6,806	8,025			
1960	21,615.83	21,829	25,939			
1961	46,479.75	46,560	55,776			
1962	542.50	539	651			
1963	5,057.50	4,978	6,069			
1964	11,839.33	11,543	14,207			
1965	738.45	713	886			
1966	20,478.61	19,561	24,337	237	13.26	18
1967	16,751.91	15,822	19,685	417	13.84	30
1968	62,491.61	58,331	72,572	2,418	14.44	167
1969	2,833.73	2,613	3,251	149	15.06	10
1970	116,038.87	105,592	131,371	7,876	15.71	501
1971	61,579.33	55,274	68,768	5,127	16.38	313
1972	1,666.69	1,474	1,834	166	17.08	10
1973	8,849.05	7,709	9,591	1,028	17.81	58
1974	674.59	578	719	91	18.56	5
1975	135,648.10	114,371	142,293	20,485	19.33	1,060
1976	83,443.84	69,123	85,999	14,134	20.13	702
1977	121,789.69	99,043	123,223	22,925	20.95	1,094
1978	63,847.48	50,933	63,368	13,249	21.79	608
1979	13,159.73	10,289	12,801	2,991	22.65	132
1980	74,236.30	56,835	70,711	18,373	23.53	781
1981	173,571.73	130,002	161,740	46,546	24.43	1,905
1982	35,274.38	25,827	32,132	10,197	25.34	402
1983	2,105.70	1,506	1,874	653	26.27	25
1984	50,704.79	35,375	44,011	16,835	27.21	619
1985	387,179.03	263,330	327,619	136,996	28.16	4,865
1986	11,421.22	7,565	9,412	4,293	29.12	147
1987	26,541.46	17,106	21,282	10,568	30.09	351
1988	13,791.68	8,642	10,752	5,798	31.06	187
1989	52,993.65	32,236	40,106	23,486	32.05	733
1990	246,551.07	145,519	181,046	114,815	33.03	3,476
1991	92,671.75	53,003	65,943	45,263	34.02	1,330
1992	889,281.27	492,356	612,558	454,580	35.01	12,984
1993	332,351.31	177,874	221,300	177,522	36.01	4,930

THE POTOMAC EDISON COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 65-S4
NET SALVAGE PERCENT.. -20

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1994	1,008,542.02	521,158	648,392	561,858	37.01	15,181
1995	689,934.43	343,902	427,861	400,060	38.00	10,528
1996	113,966.53	54,704	68,059	68,701	39.00	1,762
1998	340,345.48	150,799	187,615	220,800	41.00	5,385
2000	386,592.21	157,015	195,348	268,563	43.00	6,246
2001	31,824.63	12,338	15,350	22,840	44.00	519
2003	1,169,905.60	410,370	510,557	893,330	46.00	19,420
2004	28,610.63	9,507	11,828	22,505	47.00	479
2005	255,819.02	80,288	99,889	207,094	48.00	4,314
2006	197,711.71	58,400	72,658	164,596	49.00	3,359
2007	54,033.83	14,963	18,616	46,225	50.00	924
2008	1,011,054.43	261,313	325,109	888,156	51.00	17,415
2009	111,569.20	26,777	33,314	100,569	52.00	1,934
2010	701,575.54	155,430	193,377	648,514	53.00	12,236
2013	19,438.11	3,230	4,019	19,307	56.00	345
2015	40,278.62	5,205	6,476	41,858	58.00	722
2016	193,887.04	21,477	26,720	205,944	59.00	3,491
2017	87,812.46	8,105	10,084	95,291	60.00	1,588
2018	98,943.80	7,307	9,091	109,642	61.00	1,797
2019	333,954.57	18,494	23,009	377,736	62.00	6,093
2020	91,440.48	3,376	4,200	105,529	63.00	1,675
2021	1,079,386.76	19,921	24,784	1,270,480	64.00	19,851
2022	103.66		0	125	64.75	2
	11,344,560.25	4,605,879	5,716,535	7,896,937		172,709

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.7 1.52

THE POTOMAC EDISON COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 65-R2.5
NET SALVAGE PERCENT.. -20

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1940	9,640.98	9,876	11,569			
1943	5,751.03	5,802	6,901			
1946	3,052.69	3,028	3,663			
1947	29,151.96	28,739	34,982			
1949	63,815.53	62,111	76,579			
1950	7,906.15	7,642	9,487			
1951	69,471.01	66,666	83,365			
1952	104,112.13	99,179	124,935			
1953	65,240.02	61,667	78,281	7	13.80	1
1954	81,893.07	76,773	97,457	815	14.22	57
1955	54,999.34	51,134	64,910	1,089	14.64	74
1956	169,975.77	156,650	198,853	5,118	15.08	339
1957	102,653.57	93,753	119,011	4,173	15.53	269
1958	153,381.37	138,752	176,133	7,925	16.00	495
1959	256,208.47	229,499	291,329	16,121	16.48	978
1960	329,176.92	291,882	370,518	24,494	16.97	1,443
1961	286,104.78	251,050	318,686	24,640	17.47	1,410
1962	38,104.15	33,070	41,979	3,746	17.99	208
1963	114,576.17	98,295	124,777	12,714	18.53	686
1964	168,270.51	142,684	181,125	20,800	19.07	1,091
1965	66,964.57	56,090	71,201	9,156	19.63	466
1966	239,646.11	198,206	251,605	35,970	20.20	1,781
1967	255,809.78	208,836	265,099	41,873	20.78	2,015
1968	405,816.69	326,876	414,940	72,040	21.37	3,371
1969	436,900.46	347,074	440,580	83,701	21.97	3,810
1970	1,779,890.83	1,393,569	1,769,012	366,857	22.59	16,240
1971	543,554.34	419,354	532,333	119,932	23.21	5,167
1972	299,355.87	227,419	288,688	70,539	23.85	2,958
1973	775,480.67	579,824	736,035	194,542	24.50	7,940
1974	535,678.50	394,097	500,271	142,543	25.15	5,668
1975	938,734.10	679,009	861,942	264,539	25.82	10,246
1976	1,535,342.37	1,091,555	1,385,632	456,779	26.49	17,243
1977	1,610,099.30	1,124,204	1,427,077	505,042	27.18	18,581
1978	848,715.42	581,774	738,511	279,948	27.87	10,045
1979	730,435.21	491,124	623,438	253,084	28.58	8,855
1980	700,312.38	461,685	586,068	254,307	29.29	8,682
1981	734,783.11	474,649	602,525	279,215	30.01	9,304
1982	1,000,941.88	633,272	803,883	397,247	30.73	12,927
1983	1,344,679.90	832,384	1,056,638	556,978	31.47	17,699
1984	1,568,993.54	949,793	1,205,678	677,114	32.21	21,022
1985	3,170,882.80	1,875,590	2,380,895	1,424,164	32.96	43,209
1986	299,037.64	172,687	219,211	139,634	33.72	4,141
1987	657,344.64	370,253	470,003	318,811	34.49	9,244

THE POTOMAC EDISON COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 65-R2.5						
NET SALVAGE PERCENT.. -20						
1988	1,251,601.71	687,189	872,325	629,597	35.26	17,856
1989	4,757,670.32	2,543,679	3,228,975	2,480,229	36.04	68,819
1990	3,477,561.38	1,808,527	2,295,765	1,877,309	36.83	50,972
1991	3,700,768.94	1,869,984	2,373,779	2,067,144	37.63	54,933
1992	3,241,727.09	1,590,145	2,018,548	1,871,525	38.43	48,700
1993	1,908,304.68	907,880	1,152,473	1,137,493	39.23	28,995
1994	8,081,773.61	3,722,627	4,725,545	4,972,583	40.05	124,159
1995	5,220,997.51	2,325,829	2,952,434	3,312,763	40.87	81,056
1996	3,248,391.63	1,397,302	1,773,751	2,124,319	41.70	50,943
1997	409,823.49	170,006	215,808	275,980	42.53	6,489
1998	3,545,998.40	1,416,002	1,797,489	2,457,709	43.37	56,668
1999	787,452.51	302,089	383,475	561,468	44.22	12,697
2000	5,222,558.00	1,921,609	2,439,312	3,827,758	45.07	84,929
2001	2,715,863.66	956,136	1,213,730	2,045,306	45.93	44,531
2002	730,515.38	245,585	311,748	564,870	46.79	12,072
2003	2,695,764.67	862,979	1,095,475	2,139,443	47.66	44,890
2004	7,406,797.74	2,252,081	2,858,817	6,029,340	48.53	124,239
2005	6,192,694.63	1,782,381	2,262,575	5,168,659	49.41	104,608
2006	2,678,445.78	726,877	922,706	2,291,429	50.30	45,555
2007	3,807,344.70	971,421	1,233,133	3,335,681	51.18	65,175
2008	20,793,537.73	4,959,758	6,295,973	18,656,272	52.08	358,223
2009	6,457,259.06	1,432,892	1,818,929	5,929,782	52.98	111,925
2010	3,296,161.94	676,689	858,997	3,096,397	53.88	57,468
2011	1,315,598.87	248,222	315,096	1,263,623	54.78	23,067
2012	839,518.24	144,142	182,975	824,447	55.70	14,802
2013	5,028,130.10	778,837	988,664	5,045,092	56.61	89,120
2014	2,070,479.77	285,527	362,451	2,122,125	57.53	36,887
2015	74,087.90	8,959	11,373	77,532	58.45	1,326
2016	9,437,900.40	979,201	1,243,009	10,082,471	59.38	169,796
2017	5,265,034.23	455,847	578,657	5,739,384	60.31	95,165
2018	3,215,263.97	223,204	283,338	3,574,979	61.24	58,377
2019	8,462,656.34	442,157	561,279	9,593,909	62.17	154,317
2020	9,676,534.50	337,672	428,645	11,183,196	63.11	177,202
2021	8,232,991.60	142,859	181,347	9,698,243	64.06	151,393
2022	9,093,435.03	40,266	51,114	10,861,008	64.76	167,712
	186,933,531.24	55,414,136	70,335,515	153,984,723		3,042,731

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 50.6   1.63

THE POTOMAC EDISON COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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.. -125						
1945	250,590.32	503,578	430,712	133,116	7.48	17,796
1953	1,120,183.68	2,134,437	1,825,591	694,822	10.72	64,815
1954	112,403.12	212,369	181,640	71,267	11.22	6,352
1955	194,470.11	364,109	311,424	126,134	11.75	10,735
1956	141,301.65	262,110	224,184	93,745	12.29	7,628
1957	144,510.04	265,415	227,010	98,138	12.86	7,631
1958	281,354.97	511,415	437,415	195,634	13.45	14,545
1959	384,573.30	691,488	591,432	273,858	14.06	19,478
1960	218,353.28	388,123	331,963	159,332	14.70	10,839
1961	430,457.01	756,285	646,853	321,675	15.34	20,970
1962	468,903.19	813,883	696,117	358,915	16.00	22,432
1963	461,218.63	790,614	676,215	361,527	16.67	21,687
1964	440,950.39	746,227	638,250	353,888	17.35	20,397
1965	452,682.16	756,048	646,650	371,885	18.04	20,614
1966	498,400.68	821,191	702,367	419,035	18.74	22,360
1967	562,172.65	913,249	781,105	483,783	19.46	24,860
1968	765,618.70	1,226,022	1,048,621	674,021	20.18	33,400
1969	647,884.90	1,022,299	874,376	583,365	20.91	27,899
1970	755,795.59	1,174,580	1,004,622	695,918	21.65	32,144
1971	919,843.84	1,407,361	1,203,720	865,929	22.40	38,658
1972	826,364.23	1,243,885	1,063,899	795,421	23.17	34,330
1973	627,465.80	928,963	794,545	617,253	23.94	25,783
1974	1,014,342.56	1,475,967	1,262,399	1,019,872	24.73	41,240
1975	618,656.81	884,504	756,519	635,459	25.52	24,900
1976	776,671.06	1,090,202	932,453	815,057	26.33	30,955
1977	873,414.74	1,202,967	1,028,902	936,281	27.15	34,485
1978	816,798.28	1,103,468	943,800	893,996	27.97	31,963
1979	859,210.57	1,137,567	972,965	960,259	28.81	33,331
1980	1,251,725.95	1,623,054	1,388,203	1,428,180	29.66	48,152
1981	1,426,651.93	1,810,421	1,548,459	1,661,508	30.52	54,440
1982	1,437,996.85	1,785,054	1,526,762	1,708,731	31.38	54,453
1983	1,174,422.94	1,424,651	1,218,509	1,423,943	32.26	44,140
1984	1,402,996.81	1,662,246	1,421,724	1,735,019	33.14	52,354
1985	1,660,324.45	1,919,642	1,641,876	2,093,854	34.03	61,530
1986	1,162,359.71	1,310,270	1,120,678	1,494,631	34.93	42,789
1987	1,094,541.81	1,201,807	1,027,909	1,434,810	35.84	40,034
1988	1,082,111.35	1,156,166	988,873	1,445,878	36.76	39,333
1989	1,192,811.96	1,239,150	1,059,849	1,623,978	37.68	43,099
1990	1,882,932.42	1,899,818	1,624,920	2,611,678	38.61	67,643
1991	1,915,315.32	1,875,218	1,603,880	2,705,579	39.54	68,426
1992	1,809,617.45	1,717,051	1,468,599	2,603,040	40.48	64,304
1993	1,923,128.52	1,766,038	1,510,498	2,816,541	41.43	67,983
1994	2,988,080.66	2,652,766	2,268,919	4,454,262	42.38	105,103

THE POTOMAC EDISON COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 70-R4
NET SALVAGE PERCENT.. -125

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1995	2,210,611.02	1,895,046	1,620,839	3,353,036	43.33	77,384
1996	2,173,675.95	1,796,331	1,536,408	3,354,363	44.29	75,736
1997	2,472,530.23	1,966,199	1,681,696	3,881,497	45.26	85,760
1998	4,720,518.43	3,606,629	3,084,762	7,536,404	46.23	163,020
1999	1,370,911.74	1,004,669	859,297	2,225,254	47.20	47,145
2000	892,373.59	626,165	535,561	1,472,280	48.17	30,564
2001	3,611,680.68	2,420,494	2,070,256	6,056,026	49.15	123,215
2002	94,743.94	60,512	51,756	161,418	50.13	3,220
2003	640,277.74	388,767	332,514	1,108,111	51.11	21,681
2004	1,103,082.66	635,028	543,142	1,938,794	52.09	37,220
2005	2,646,366.81	1,439,220	1,230,970	4,723,355	53.08	88,986
2006	679,984.58	348,174	297,794	1,232,171	54.07	22,788
2007	2,939,932.49	1,411,807	1,207,523	5,407,325	55.06	98,208
2008	7,083,953.91	3,176,463	2,716,839	13,222,057	56.05	235,898
2009	1,131,529.96	471,356	403,152	2,142,790	57.04	37,566
2010	5,354,577.72	2,060,174	1,762,074	10,285,726	58.03	177,248
2011	3,613,055.10	1,273,954	1,089,617	7,039,757	59.03	119,257
2012	6,541,671.66	2,098,454	1,794,815	12,923,946	60.02	215,327
2013	2,347,409.29	677,586	579,541	4,702,130	61.02	77,059
2014	4,303,700.82	1,105,255	945,328	8,737,999	62.01	140,913
2015	2,997,318.75	673,453	576,007	6,167,960	63.01	97,889
2016	4,103,649.97	790,086	675,763	8,557,449	64.01	133,689
2017	3,680,927.97	590,430	504,997	7,777,091	65.01	119,629
2018	5,383,870.25	692,177	592,021	11,521,687	66.00	174,571
2019	4,209,358.42	405,929	347,192	9,123,864	67.00	136,177
2020	6,082,965.92	391,028	334,448	13,352,225	68.00	196,356
2021	7,024,249.33	225,847	193,167	15,611,394	69.00	226,252
2022	3,167,199.58	25,441	21,760	7,104,439	69.75	101,856
	131,651,738.90	82,128,352	70,244,646	225,971,766		4,620,624

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.9 3.51

THE POTOMAC EDISON COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 62-R1
NET SALVAGE PERCENT.. -100

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1945	644,479.04	954,873	684,358	604,600	16.07	37,623
1953	895,398.75	1,227,556	879,791	911,006	19.50	46,718
1954	111,190.94	150,826	108,097	114,285	19.95	5,729
1955	152,221.62	204,224	146,368	158,075	20.41	7,745
1956	123,645.44	164,050	117,575	129,716	20.87	6,215
1957	112,393.94	147,418	105,655	119,133	21.34	5,583
1958	209,224.37	271,251	194,406	224,043	21.81	10,272
1959	310,197.01	397,350	284,781	335,613	22.29	15,057
1960	180,585.58	228,527	163,786	197,385	22.77	8,669
1961	400,364.55	500,328	358,586	442,143	23.26	19,009
1962	431,487.68	532,404	381,574	481,401	23.75	20,270
1963	369,959.70	450,515	322,885	417,034	24.25	17,197
1964	369,804.46	444,246	318,392	421,217	24.76	17,012
1965	402,574.73	476,987	341,857	463,292	25.27	18,334
1966	462,636.30	540,387	387,296	537,977	25.79	20,860
1967	524,877.14	604,291	433,096	616,658	26.31	23,438
1968	862,985.97	978,799	701,506	1,024,466	26.84	38,169
1969	596,143.19	665,952	477,288	714,998	27.37	26,123
1970	656,803.99	722,274	517,654	795,954	27.91	28,519
1971	425,447.84	460,445	330,001	520,895	28.45	18,309
1972	652,132.00	694,208	497,540	806,724	29.00	27,818
1973	355,831.35	372,363	266,873	444,790	29.56	15,047
1974	542,330.32	557,722	399,720	684,941	30.12	22,740
1975	1,777.61	1,795	1,286	2,269	30.69	74
1976	989,433.43	981,142	703,185	1,275,682	31.26	40,809
1977	940,522.51	915,034	655,806	1,225,239	31.84	38,481
1978	735,727.15	702,031	503,146	968,308	32.42	29,868
1979	778,635.94	728,149	521,865	1,035,407	33.01	31,366
1980	1,272,085.73	1,164,976	834,939	1,709,232	33.61	50,855
1981	1,299,608.75	1,165,463	835,288	1,763,930	34.20	51,577
1982	1,227,085.50	1,076,277	771,369	1,682,802	34.81	48,342
1983	735,887.76	630,965	452,213	1,019,563	35.42	28,785
1984	595,161.43	498,591	357,341	832,982	36.03	23,119
1985	1,178,245.00	963,498	690,540	1,665,950	36.65	45,456
1986	866,553.19	691,007	495,245	1,237,861	37.28	33,204
1987	612,538.73	476,004	341,153	883,924	37.91	23,316
1988	602,186.81	455,723	326,617	877,757	38.54	22,775
1989	690,700.86	508,439	364,399	1,017,003	39.18	25,957
1990	1,369,164.76	979,610	702,087	2,036,243	39.82	51,136
1991	1,185,870.74	823,611	590,283	1,781,458	40.47	44,019
1992	2,073,849.04	1,396,820	1,001,102	3,146,596	41.12	76,522
1993	2,071,334.86	1,351,712	968,773	3,173,897	41.77	75,985
1994	3,377,400.65	2,132,153	1,528,116	5,226,685	42.43	123,184

THE POTOMAC EDISON COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 62-R1						
NET SALVAGE PERCENT.. -100						
1995	2,545,801.14	1,552,939	1,112,993	3,978,609	43.09	92,333
1996	1,876,746.05	1,104,840	791,840	2,961,652	43.75	67,695
1997	3,065,237.60	1,738,296	1,245,838	4,884,637	44.42	109,965
1998	5,931,495.97	3,235,512	2,318,895	9,544,097	45.09	211,668
1999	846,969.46	443,710	318,007	1,375,932	45.76	30,068
2000	1,076,056.29	540,116	387,102	1,765,011	46.44	38,006
2001	3,109,471.60	1,492,546	1,069,709	5,149,234	47.12	109,279
2002	201,570.18	92,331	66,174	336,966	47.80	7,049
2003	677,300.12	295,384	211,702	1,142,898	48.48	23,575
2004	1,136,683.78	470,451	337,173	1,936,195	49.17	39,378
2005	3,303,623.82	1,294,822	928,000	5,679,248	49.85	113,927
2006	1,112,958.05	411,438	294,878	1,931,038	50.54	38,208
2007	2,263,823.54	785,773	563,164	3,964,483	51.24	77,371
2008	4,467,470.82	1,451,213	1,040,086	7,894,856	51.93	152,029
2009	1,241,586.69	375,282	268,965	2,214,208	52.63	42,071
2010	3,783,934.89	1,058,291	758,478	6,809,392	53.33	127,684
2011	4,624,473.45	1,187,472	851,062	8,397,885	54.04	155,401
2012	13,497,172.13	3,161,038	2,265,519	24,728,825	54.74	451,751
2013	3,060,191.13	646,618	463,432	5,656,950	55.45	102,019
2014	6,833,681.97	1,285,142	921,063	12,746,301	56.17	226,924
2015	3,911,265.73	645,985	462,978	7,359,553	56.88	129,387
2016	6,478,185.01	919,514	659,017	12,297,353	57.60	213,496
2017	5,598,530.18	662,754	474,996	10,722,064	58.33	183,817
2018	9,064,774.07	859,703	616,150	17,513,398	59.06	296,536
2019	9,602,616.32	684,667	490,702	18,714,531	59.79	313,004
2020	10,084,138.09	481,417	345,032	19,823,244	60.52	327,549
2021	7,177,268.13	171,393	122,837	14,231,699	61.26	232,316
2022	2,526,404.97	15,462	11,082	5,041,728	61.81	81,568
	151,495,917.54	56,454,105	40,460,712	262,531,123		5,315,360

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 49.4 3.51

THE POTOMAC EDISON COMPANY

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
1945	198,445.64	177,240	198,446			
1953	257,267.91	217,870	257,268			
1954	26,518.65	22,268	26,519			
1955	49,708.01	41,364	49,708			
1956	17,511.50	14,437	17,512			
1957	31,497.90	25,711	31,498			
1958	63,506.77	51,305	63,507			
1959	68,670.28	54,877	68,670			
1960	35,567.72	28,098	35,568			
1961	62,506.71	48,809	62,507			
1962	66,463.18	51,272	66,463			
1963	63,613.40	48,465	63,613			
1964	51,627.12	38,831	51,627			
1965	58,305.14	43,279	58,305			
1966	79,089.94	57,917	79,090			
1967	72,188.05	52,120	72,188			
1968	118,936.55	84,648	118,937			
1969	104,544.79	73,316	104,545			
1970	56,851.56	39,268	56,852			
1971	160,188.37	108,928	160,188			
1972	135,363.03	90,558	135,363			
1973	49,931.61	32,855	49,932			
1974	61,543.99	39,801	61,544			
1975	36,942.81	23,475	36,943			
1976	26,122.80	16,297	26,123			
1977	16,917.10	10,356	16,917			
1978	44,528.17	26,736	44,528			
1979	33,294.54	19,592	33,295			
1980	26,021.09	14,996	26,021			
1981	17,176.51	9,688	17,177			
1982	91,864.42	50,683	90,455	1,409	31.38	45
1983	47,413.39	25,562	45,621	1,792	32.26	56
1984	58,369.07	30,735	54,854	3,515	33.14	106
1985	99,949.36	51,360	91,664	8,285	34.03	243
1986	51,623.71	25,863	46,158	5,466	34.93	156
1987	56,351.74	27,500	49,080	7,272	35.84	203
1988	76,307.29	36,235	64,670	11,637	36.76	317
1989	57,472.69	26,536	47,360	10,113	37.68	268
1990	145,517.80	65,255	116,462	29,056	38.61	753
1991	222,430.29	96,788	172,740	49,690	39.54	1,257
1992	169,561.57	71,506	127,619	41,943	40.48	1,036
1993	293,634.53	119,844	213,889	79,746	41.43	1,925
1994	247,471.71	97,645	174,270	73,202	42.38	1,727

THE POTOMAC EDISON COMPANY

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
1995	336,884.25	128,353	229,075	107,809	43.33	2,488
1996	211,127.65	77,545	138,397	72,731	44.29	1,642
1997	77,354.70	27,339	48,793	28,562	45.26	631
1998	511,739.12	173,771	310,134	201,605	46.23	4,361
1999	64,632.73	21,052	37,572	27,061	47.20	573
2000	26,542.18	8,277	14,772	11,770	48.17	244
2001	269,299.37	80,214	143,160	126,139	49.15	2,566
2002	6,176.60	1,753	3,129	3,048	50.13	61
2003	13,037.11	3,518	6,279	6,758	51.11	132
2004	115,193.78	29,473	52,601	62,593	52.09	1,202
2005	964,066.98	233,025	415,886	548,181	53.08	10,327
2006	54,368.26	12,373	22,082	32,286	54.07	597
2009	5,607.89	1,038	1,853	3,755	57.04	66
2011	3,583,609.65	561,587	1,002,280	2,581,330	59.03	43,729
2012	2,000.53	285	509	1,492	60.02	25
2013	23,172,747.85	2,972,832	5,305,698	17,867,050	61.02	292,806
2014	2,724,673.77	310,994	555,040	2,169,634	62.01	34,988
2015	9,549,735.28	953,637	1,701,983	7,847,752	63.01	124,548
2016	9,628,276.49	823,892	1,470,423	8,157,853	64.01	127,447
2017	2,403,223.79	171,326	305,770	2,097,454	65.01	32,264
2018	8,220,756.12	469,734	838,348	7,382,408	66.00	111,855
2019	4,013,147.47	172,004	306,980	3,706,167	67.00	55,316
2020	3,903,913.96	111,535	199,060	3,704,854	68.00	54,483
2021	4,108,534.21	58,711	104,783	4,003,751	69.00	58,025
2022	38,208.87	136	243	37,966	69.75	544
	77,713,677.02	9,694,293	16,600,546	61,113,131		969,012

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 63.1 1.25

THE POTOMAC EDISON COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 65-R4
NET SALVAGE PERCENT.. -50

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1964	1,065.97	1,270	1,220	379	13.37	28
1965	3,441.97	4,050	3,892	1,271	14.01	91
1966	42,985.37	49,926	47,975	16,503	14.67	1,125
1967	24,198.31	27,731	26,648	9,649	15.34	629
1968	24,786.03	28,016	26,921	10,258	16.02	640
1969	39,680.53	44,219	42,491	17,030	16.71	1,019
1970	25,335.98	27,825	26,738	11,266	17.41	647
1971	30,636.17	33,144	31,849	14,105	18.12	778
1972	106,360.09	113,297	108,871	50,669	18.84	2,689
1973	319,345.25	334,795	321,715	157,303	19.57	8,038
1974	329,428.91	339,664	326,394	167,749	20.32	8,255
1975	249,671.72	253,111	243,222	131,286	21.07	6,231
1976	479,289.48	477,372	458,722	260,212	21.84	11,914
1977	404,216.25	395,323	379,878	226,446	22.62	10,011
1978	536,944.55	515,346	495,212	310,205	23.41	13,251
1979	538,814.09	507,062	487,252	320,969	24.22	13,252
1980	586,246.21	540,742	519,616	359,753	25.03	14,373
1981	370,766.47	334,886	321,802	234,348	25.86	9,062
1982	348,166.71	307,804	295,779	226,471	26.69	8,485
1983	446,912.40	386,340	371,246	299,123	27.54	10,861
1984	376,162.61	317,714	305,301	258,943	28.40	9,118
1985	821,197.23	677,303	650,842	580,954	29.26	19,855
1986	883,472.99	710,723	682,956	642,253	30.14	21,309
1987	803,670.10	630,021	605,407	600,098	31.03	19,339
1988	1,027,170.99	784,122	753,488	787,268	31.92	24,664
1989	1,104,286.16	819,800	787,772	868,657	32.83	26,459
1990	1,305,531.46	941,784	904,990	1,053,307	33.74	31,218
1991	1,127,295.33	789,281	758,445	932,498	34.66	26,904
1992	1,335,101.81	906,441	871,028	1,131,625	35.58	31,805
1993	1,500,777.35	986,348	947,813	1,303,353	36.52	35,689
1994	1,837,020.52	1,167,491	1,121,879	1,633,652	37.46	43,611
1995	2,547,665.21	1,563,872	1,502,774	2,318,724	38.40	60,383
1996	1,723,797.10	1,020,367	980,503	1,605,193	39.35	40,793
1997	3,498,702.66	1,993,473	1,915,591	3,332,463	40.31	82,671
1998	5,071,671.78	2,777,349	2,668,842	4,938,666	41.27	119,667
1999	230,354.02	121,043	116,314	229,217	42.23	5,428
2000	2,242,005.30	1,127,886	1,083,821	2,279,187	43.20	52,759
2001	5,911,100.92	2,841,407	2,730,397	6,136,254	44.17	138,924
2002	338,059.67	154,855	148,805	358,285	45.15	7,935
2003	264,990.08	115,394	110,886	286,599	46.13	6,213
2004	2,246,607.61	927,501	891,265	2,478,646	47.11	52,614
2005	2,616,416.24	1,020,991	981,102	2,943,522	48.09	61,209
2006	770,525.36	283,076	272,017	883,771	49.08	18,007

THE POTOMAC EDISON COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 65-R4						
NET SALVAGE PERCENT.. -50						
2007	2,257,391.75	778,292	747,885	2,638,203	50.06	52,701
2008	2,187,063.81	704,081	676,573	2,604,023	51.05	51,009
2009	382,527.20	114,402	109,932	463,859	52.04	8,914
2010	1,022,572.17	282,230	271,204	1,262,654	53.04	23,806
2011	1,437,126.81	363,816	349,602	1,806,088	54.03	33,428
2012	939,020.96	216,266	207,817	1,200,714	55.02	21,823
2013	1,267,034.71	262,561	252,303	1,648,249	56.02	29,423
2014	759,422.93	139,852	134,388	1,004,746	57.02	17,621
2015	961,871.62	155,160	149,098	1,293,709	58.01	22,301
2016	1,203,095.28	166,298	159,801	1,644,842	59.01	27,874
2017	1,060,830.00	122,160	117,387	1,473,858	60.01	24,560
2018	1,233,635.40	113,877	109,428	1,741,025	61.00	28,541
2019	2,642,034.18	182,895	175,750	3,787,301	62.00	61,086
2020	2,012,718.13	92,897	89,268	2,929,809	63.00	46,505
2021	2,183,234.73	50,367	48,399	3,226,453	64.00	50,413
2022	713,219.22	4,119	3,958	1,065,871	64.75	16,461
	66,754,673.86	31,149,438	29,932,474	70,199,537		1,574,419

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.6   2.36

THE POTOMAC EDISON COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 44-R3
NET SALVAGE PERCENT.. -50

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1966	9,176.93	12,323	8,902	4,863	4.61	1,055
1967	7,336.06	9,784	7,068	3,936	4.88	807
1968	31,633.89	41,875	30,251	17,200	5.17	3,327
1969	48,368.58	63,550	45,910	26,643	5.46	4,880
1970	75,607.49	98,538	71,186	42,225	5.77	7,318
1971	95,505.53	123,397	89,145	54,113	6.10	8,871
1972	71,140.41	91,092	65,807	40,904	6.44	6,352
1973	64,600.01	81,946	59,200	37,700	6.79	5,552
1974	466,780.44	586,078	423,396	276,775	7.17	38,602
1975	518,107.46	643,629	464,972	312,189	7.56	41,295
1976	545,677.88	670,071	484,075	334,442	7.98	41,910
1977	799,577.34	969,855	700,645	498,721	8.42	59,231
1978	909,243.36	1,088,610	786,437	577,428	8.88	65,026
1979	929,138.65	1,097,224	792,660	601,048	9.36	64,215
1980	898,439.97	1,045,663	755,411	592,249	9.86	60,066
1981	973,038.38	1,115,233	805,670	653,888	10.38	62,995
1982	803,004.97	905,296	654,007	550,500	10.93	50,366
1983	1,063,162.86	1,178,293	851,226	743,518	11.49	64,710
1984	922,308.95	1,003,634	725,048	658,415	12.08	54,505
1985	1,529,705.48	1,632,785	1,179,561	1,114,997	12.69	87,864
1986	1,699,896.09	1,778,516	1,284,841	1,265,003	13.31	95,042
1987	1,187,678.48	1,216,688	878,963	902,555	13.95	64,699
1988	3,351,058.70	3,357,509	2,425,541	2,601,047	14.61	178,032
1989	3,210,119.56	3,141,905	2,269,784	2,545,395	15.29	166,474
1990	4,344,150.31	4,149,663	2,997,812	3,518,413	15.98	220,176
1991	4,844,431.62	4,510,263	3,258,317	4,008,330	16.69	240,164
1992	4,100,610.94	3,717,122	2,685,334	3,465,582	17.41	199,057
1993	4,958,686.59	4,369,843	3,156,875	4,281,155	18.15	235,876
1994	5,523,451.17	4,726,279	3,414,372	4,870,805	18.90	257,715
1995	5,640,300.29	4,678,206	3,379,643	5,080,807	19.67	258,302
1996	7,642,536.21	6,138,294	4,434,444	7,029,360	20.44	343,902
1997	9,565,815.32	7,425,464	5,364,325	8,984,398	21.23	423,193
1998	19,391,468.99	14,523,822	10,492,342	18,594,861	22.03	844,070
1999	1,622,208.68	1,170,205	845,383	1,587,930	22.84	69,524
2000	3,079,053.96	2,134,015	1,541,661	3,076,920	23.67	129,992
2001	13,046,630.51	8,673,009	6,265,581	13,304,365	24.50	543,035
2002	496,490.76	315,664	228,043	516,693	25.35	20,382
2003	860,220.03	521,706	376,892	913,438	26.21	34,851
2004	1,329,976.40	767,603	554,534	1,440,431	27.07	53,211
2005	4,082,035.89	2,233,506	1,613,536	4,509,518	27.95	161,342
2006	2,598,819.60	1,343,135	970,312	2,927,917	28.84	101,523
2007	13,251,425.48	6,446,553	4,657,138	15,220,000	29.73	511,941
2008	8,880,665.84	4,044,788	2,922,047	10,398,952	30.64	339,391

THE POTOMAC EDISON COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 44-R3
NET SALVAGE PERCENT.. -50

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2009	3,779,648.61	1,604,177	1,158,894	4,510,579	31.55	142,966
2010	6,959,022.10	2,735,418	1,976,129	8,462,404	32.47	260,622
2011	8,894,737.98	3,214,247	2,322,046	11,020,061	33.40	329,942
2012	8,529,129.58	2,808,856	2,029,182	10,764,512	34.34	313,469
2013	9,575,207.99	2,846,422	2,056,320	12,306,492	35.28	348,823
2014	8,511,521.45	2,254,574	1,628,756	11,138,526	36.23	307,439
2015	10,780,715.96	2,502,797	1,808,078	14,362,996	37.19	386,206
2016	10,321,458.62	2,058,357	1,487,004	13,995,184	38.15	366,846
2017	11,191,819.68	1,865,788	1,347,888	15,439,842	39.11	394,780
2018	15,538,152.07	2,076,441	1,500,069	21,807,159	40.08	544,091
2019	21,467,511.48	2,151,689	1,554,429	30,646,838	41.06	746,392
2020	20,971,113.06	1,401,395	1,012,400	30,444,270	42.04	724,174
2021	21,355,188.74	713,370	515,355	31,517,428	43.02	732,623
2022	7,375,638.23	62,840	45,397	11,018,061	43.75	251,841
	300,720,151.61	132,139,005	95,460,244	355,619,984		12,071,055

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.5 4.01

THE POTOMAC EDISON COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R1.5						
NET SALVAGE PERCENT.. -35						
1939	270.99	329	366			
1947	337.03	390	455			
1948	336.35	387	454			
1950	868.31	986	1,172			
1951	4,523.73	5,098	6,107			
1952	9,649.36	10,796	13,027			
1953	59,213.45	65,773	79,938			
1954	11,178.62	12,323	15,091			
1955	21,377.60	23,382	28,860			
1956	52,350.33	56,807	70,673			
1957	42,701.93	45,957	57,648			
1958	41,583.45	44,382	55,726	412	10.47	39
1959	39,120.74	41,395	51,976	837	10.81	77
1960	33,616.92	35,253	44,264	1,119	11.16	100
1961	52,455.79	54,499	68,429	2,386	11.52	207
1962	32,010.81	32,938	41,357	1,858	11.89	156
1963	56,475.73	57,548	72,258	3,984	12.26	325
1964	96,781.14	97,599	122,546	8,109	12.65	641
1965	187,613.70	187,223	235,079	18,199	13.04	1,396
1966	355,336.24	350,760	440,418	39,286	13.44	2,923
1967	309,126.77	301,640	378,742	38,579	13.86	2,783
1968	556,125.38	536,350	673,446	77,323	14.28	5,415
1969	658,350.77	627,296	787,639	101,135	14.71	6,875
1970	484,374.00	455,772	572,272	81,633	15.15	5,388
1971	517,145.06	480,185	602,925	95,221	15.61	6,100
1972	361,920.54	331,559	416,309	72,284	16.07	4,498
1973	498,389.76	450,121	565,176	107,650	16.55	6,505
1974	720,616.95	641,486	805,456	167,377	17.03	9,828
1975	666,340.04	584,174	733,495	166,064	17.53	9,473
1976	799,441.92	689,854	866,187	213,060	18.04	11,810
1977	1,340,682.91	1,138,441	1,429,438	380,484	18.55	20,511
1978	1,690,530.24	1,411,322	1,772,070	510,146	19.08	26,737
1979	1,352,727.62	1,109,588	1,393,209	432,973	19.62	22,068
1980	1,287,528.89	1,037,336	1,302,489	435,675	20.16	21,611
1981	1,844,340.01	1,458,061	1,830,756	659,103	20.72	31,810
1982	1,950,776.43	1,512,183	1,898,712	734,836	21.29	34,516
1983	1,685,030.09	1,279,797	1,606,926	667,865	21.87	30,538
1984	2,411,476.80	1,793,777	2,252,284	1,003,210	22.45	44,686
1985	2,314,631.54	1,684,242	2,114,751	1,010,002	23.05	43,818
1986	3,348,837.83	2,382,531	2,991,529	1,529,402	23.65	64,668
1987	3,986,653.47	2,769,568	3,477,496	1,904,486	24.27	78,471
1988	4,729,559.94	3,206,500	4,026,113	2,358,793	24.89	94,769
1989	5,665,301.95	3,744,538	4,701,678	2,946,480	25.52	115,458

THE POTOMAC EDISON COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R1.5						
NET SALVAGE PERCENT.. -35						
1990	4,077,600.57	2,624,670	3,295,561	2,209,200	26.16	84,450
1991	2,990,186.41	1,872,245	2,350,809	1,685,943	26.81	62,885
1992	2,683,717.18	1,632,532	2,049,823	1,573,195	27.47	57,270
1993	3,695,898.93	2,182,391	2,740,231	2,249,233	28.13	79,959
1994	4,421,347.89	2,530,780	3,177,672	2,791,148	28.80	96,915
1995	20,490,785.85	11,352,715	14,254,579	13,407,982	29.48	454,816
1996	183,271.02	98,125	123,207	124,209	30.17	4,117
1997	120,154.01	62,061	77,924	84,284	30.87	2,730
1998	8,865,849.58	4,411,735	5,539,417	6,429,480	31.57	203,658
1999	305,075.71	146,043	183,373	228,479	32.27	7,080
2000	1,976,336.78	907,672	1,139,682	1,528,373	32.99	46,328
2001	9,837,948.70	4,327,025	5,433,055	7,848,176	33.71	232,814
2002	202,226.11	85,014	106,744	166,261	34.43	4,829
2003	266,077.83	106,612	133,863	225,342	35.16	6,409
2004	1,143,356.98	435,276	546,537	996,995	35.90	27,771
2005	1,901,898.48	686,053	861,415	1,706,148	36.64	46,565
2006	924,068.25	314,618	395,037	852,455	37.39	22,799
2007	6,086,846.05	1,949,130	2,447,347	5,769,895	38.14	151,282
2008	8,078,958.52	2,421,264	3,040,163	7,866,431	38.90	202,222
2009	2,599,447.34	725,714	911,214	2,598,040	39.66	65,508
2010	8,119,970.37	2,098,119	2,634,418	8,327,542	40.43	205,974
2011	10,254,105.21	2,436,375	3,059,136	10,783,906	41.20	261,745
2012	6,412,076.84	1,388,471	1,743,378	6,912,926	41.98	164,672
2013	4,271,971.21	835,085	1,048,541	4,718,620	42.76	110,351
2014	4,147,103.37	722,218	906,824	4,691,766	43.55	107,733
2015	4,707,380.98	719,382	903,263	5,451,701	44.34	122,952
2016	5,010,597.56	658,843	827,250	5,937,057	45.13	131,555
2017	5,317,916.65	584,386	733,761	6,445,426	45.93	140,332
2018	7,814,819.25	687,860	863,683	9,686,323	46.74	207,238
2019	8,016,216.75	532,437	668,533	10,153,360	47.54	213,575
2020	8,547,565.30	378,486	475,231	11,063,982	48.36	228,784
2021	7,127,753.61	157,808	198,145	9,424,322	49.18	191,629
2022	3,651,454.36	20,704	25,996	4,903,468	49.79	98,483
	204,527,694.78	80,841,995	101,500,754	174,611,634		4,749,630

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.8   2.32

THE POTOMAC EDISON COMPANY

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 65-R4						
NET SALVAGE PERCENT.. -125						
1953	82,085.86	162,445	158,473	26,220	7.83	3,349
1954	25,790.71	50,691	49,452	8,577	8.22	1,043
1956	37,083.33	71,808	70,052	13,385	9.06	1,477
1957	58,715.17	112,780	110,022	22,087	9.51	2,323
1958	48,636.17	92,613	90,349	19,082	9.99	1,910
1959	52,776.26	99,583	97,148	21,599	10.49	2,059
1960	51,651.76	96,513	94,153	22,063	11.02	2,002
1961	73,561.95	136,053	132,726	32,788	11.57	2,834
1962	78,663.43	143,909	140,390	36,603	12.15	3,013
1963	78,015.59	141,104	137,654	37,881	12.75	2,971
1964	93,427.72	166,974	162,891	47,321	13.37	3,539
1965	106,029.39	187,146	182,570	55,996	14.01	3,997
1966	127,312.49	221,804	216,381	70,072	14.67	4,777
1967	126,118.35	216,797	211,496	72,270	15.34	4,711
1968	285,348.15	483,798	471,969	170,064	16.02	10,616
1969	219,733.13	367,299	358,318	136,082	16.71	8,144
1970	380,272.73	626,438	611,121	244,493	17.41	14,043
1971	533,986.71	866,536	845,349	356,121	18.12	19,653
1972	607,358.53	970,460	946,732	419,825	18.84	22,284
1973	751,171.82	1,181,270	1,152,387	537,750	19.57	27,478
1974	744,273.53	1,151,097	1,122,952	551,663	20.32	27,149
1975	815,529.02	1,240,144	1,209,822	625,118	21.07	29,669
1976	878,855.45	1,313,010	1,280,906	696,519	21.84	31,892
1977	713,647.20	1,046,920	1,021,322	584,384	22.62	25,835
1978	810,823.05	1,167,312	1,138,771	685,581	23.41	29,286
1979	903,294.95	1,275,096	1,243,919	788,495	24.22	32,556
1980	922,062.39	1,275,738	1,244,545	830,095	25.03	33,164
1981	1,096,018.59	1,484,927	1,448,620	1,017,422	25.86	39,343
1982	697,225.09	924,594	901,987	666,769	26.69	24,982
1983	1,057,132.82	1,370,781	1,337,265	1,041,284	27.54	37,810
1984	928,838.50	1,176,773	1,148,000	941,887	28.40	33,165
1985	870,221.94	1,076,606	1,050,282	907,717	29.26	31,022
1986	1,027,977.40	1,240,458	1,210,128	1,102,821	30.14	36,590
1987	1,039,892.48	1,222,804	1,192,906	1,146,852	31.03	36,959
1988	1,345,071.05	1,540,201	1,502,542	1,523,868	31.92	47,740
1989	1,704,635.35	1,898,231	1,851,818	1,983,612	32.83	60,421
1990	2,066,694.24	2,236,308	2,181,629	2,468,433	33.74	73,160
1991	1,609,467.09	1,690,315	1,648,986	1,972,315	34.66	56,905
1992	1,700,215.22	1,731,491	1,689,155	2,136,329	35.58	60,043
1993	2,364,757.38	2,331,267	2,274,266	3,046,438	36.52	83,418
1994	1,757,798.05	1,675,713	1,634,741	2,320,305	37.46	61,941
1995	1,350,609.22	1,243,597	1,213,190	1,825,681	38.40	47,544
1996	2,599,926.16	2,308,461	2,252,018	3,597,816	39.35	91,431

THE POTOMAC EDISON COMPANY

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 65-R4
NET SALVAGE PERCENT.. -125

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1997	789,763.83	674,982	658,478	1,118,491	40.31	27,747
1998	4,959,085.61	4,073,542	3,973,941	7,184,002	41.27	174,073
1999	16,199.57	12,768	12,456	23,993	42.23	568
2000	288,118.68	217,416	212,100	436,167	43.20	10,096
2001	5,613,507.78	4,047,536	3,948,571	8,681,822	44.17	196,555
2002	7,587.00	5,213	5,086	11,985	45.15	265
2003	11,349.51	7,413	7,232	18,304	46.13	397
2004	96,108.09	59,517	58,062	158,181	47.11	3,358
2005	337,224.60	197,390	192,564	566,191	48.09	11,774
2006	46,378.56	25,558	24,933	79,419	49.08	1,618
2007	2,531,030.72	1,308,954	1,276,949	4,417,870	50.06	88,251
2008	601,410.78	290,418	283,317	1,069,857	51.05	20,957
2009	713,968.13	320,290	312,459	1,293,969	52.04	24,865
2010	438,728.95	181,634	177,193	809,947	53.04	15,270
2011	1,084,549.28	411,839	401,769	2,038,467	54.03	37,728
2012	928,868.29	320,891	313,045	1,776,909	55.02	32,296
2013	1,493,452.74	464,221	452,870	2,907,399	56.02	51,899
2014	1,482,599.73	409,542	399,529	2,936,320	57.02	51,496
2015	1,698,228.26	410,912	400,865	3,420,149	58.01	58,958
2016	2,350,254.57	487,296	475,381	4,812,692	59.01	81,557
2017	2,560,180.92	442,226	431,413	5,328,994	60.01	88,802
2018	2,315,660.48	320,638	312,798	4,897,438	61.00	80,286
2019	2,398,695.73	249,075	242,985	5,154,080	62.00	83,130
2020	2,975,159.09	205,978	200,942	6,493,166	63.00	103,066
2021	2,839,318.15	98,255	95,853	6,292,613	64.00	98,322
2022	1,621,455.72	14,046	13,702	3,634,573	64.75	56,132
	73,021,590.19	55,275,415	53,923,896	110,374,681		2,573,714

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.9   3.52

THE POTOMAC EDISON COMPANY

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 42-R2.5						
NET SALVAGE PERCENT.. -30						
1953	13,183.95	16,168	17,139			
1954	6,916.76	8,427	8,992			
1955	7,449.82	9,021	9,685			
1956	19,217.81	23,133	24,983			
1957	12,018.05	14,385	15,600	23	3.33	7
1958	15,173.10	18,058	19,583	142	3.55	40
1959	19,884.25	23,529	25,516	334	3.77	89
1960	18,862.17	22,197	24,072	449	3.98	113
1961	15,296.04	17,896	19,408	477	4.20	114
1962	3,389.01	3,941	4,274	132	4.43	30
1963	16,552.35	19,131	20,747	771	4.66	165
1964	17,656.51	20,281	21,994	959	4.89	196
1965	22,558.27	25,744	27,919	1,407	5.13	274
1966	36,663.30	41,568	45,079	2,583	5.37	481
1967	28,752.31	32,376	35,111	2,267	5.62	403
1968	36,623.60	40,945	44,404	3,207	5.88	545
1969	33,339.84	37,006	40,132	3,210	6.14	523
1970	48,329.92	53,225	57,721	5,108	6.42	796
1971	46,057.55	50,324	54,575	5,300	6.70	791
1972	58,980.37	63,895	69,292	7,382	7.00	1,055
1973	188,986.94	202,863	219,998	25,685	7.32	3,509
1974	225,229.65	239,468	259,695	33,104	7.65	4,327
1975	130,401.78	137,232	148,824	20,698	8.00	2,587
1976	213,198.36	221,923	240,668	36,490	8.37	4,360
1977	238,819.61	245,786	266,547	43,918	8.75	5,019
1978	270,280.95	274,732	297,938	53,427	9.16	5,833
1979	245,441.43	246,220	267,018	52,056	9.59	5,428
1980	299,881.56	296,653	321,711	68,135	10.04	6,786
1981	402,139.91	391,961	425,069	97,713	10.51	9,297
1982	312,464.32	299,819	325,144	81,060	11.00	7,369
1983	497,832.07	469,822	509,507	137,675	11.51	11,961
1984	499,130.41	462,858	501,955	146,915	12.04	12,202
1985	503,699.90	458,524	497,255	157,555	12.59	12,514
1986	535,338.55	477,881	518,247	177,693	13.16	13,503
1987	553,792.05	484,412	525,329	194,601	13.74	14,163
1988	881,118.78	754,087	817,783	327,671	14.35	22,834
1989	886,382.58	741,584	804,224	348,073	14.97	23,251
1990	861,939.66	704,057	763,527	356,995	15.61	22,870
1991	931,173.55	741,883	804,548	405,978	16.26	24,968
1992	602,950.69	467,872	507,392	276,444	16.93	16,329
1993	818,450.57	617,867	670,057	393,929	17.61	22,370
1994	1,245,957.81	913,617	990,788	628,957	18.31	34,350
1995	4,418,117.65	3,142,528	3,407,971	2,335,582	19.02	122,796

THE POTOMAC EDISON COMPANY

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 42-R2.5
NET SALVAGE PERCENT.. -30

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1996	309,666.31	213,263	231,277	171,289	19.75	8,673
1997	272,099.35	181,244	196,553	157,176	20.48	7,675
1998	3,642,165.05	2,341,460	2,539,238	2,195,577	21.23	103,419
1999	29,937.95	18,542	20,108	18,811	21.99	855
2000	1,740,589.74	1,036,573	1,124,130	1,138,637	22.76	50,028
2001	1,904,634.62	1,088,263	1,180,187	1,295,838	23.54	55,048
2002	42,133.15	23,031	24,976	29,797	24.34	1,224
2003	33,815.98	17,647	19,138	24,823	25.14	987
2004	1,681.89	836	907	1,279	25.95	49
2005	532,763.20	250,982	272,182	420,410	26.78	15,699
2006	131,792.45	58,701	63,659	107,671	27.61	3,900
2007	2,644,171.23	1,108,981	1,202,654	2,234,769	28.45	78,551
2008	509,037.52	199,941	216,830	444,919	29.31	15,180
2009	693,390.53	253,900	275,346	626,062	30.17	20,751
2010	1,321,242.78	448,212	486,072	1,231,544	31.04	39,676
2011	1,451,279.33	453,252	491,537	1,395,126	31.91	43,721
2012	992,941.98	282,755	306,639	984,186	32.80	30,006
2013	1,646,796.31	423,586	459,365	1,681,470	33.69	49,910
2014	946,813.59	217,160	235,503	995,355	34.59	28,776
2015	2,964,263.30	596,374	646,749	3,206,793	35.50	90,332
2016	1,597,954.51	276,494	299,849	1,777,492	36.41	48,819
2017	3,372,298.77	487,456	528,631	3,855,357	37.33	103,278
2018	2,779,959.08	322,689	349,946	3,264,001	38.25	85,333
2019	1,282,771.70	111,963	121,420	1,546,183	39.18	39,464
2020	4,719,566.88	274,622	297,819	5,837,618	40.12	145,504
2021	3,498,134.05	101,775	110,371	4,437,203	41.06	108,066
2022	1,500,666.88	11,139	12,080	1,938,787	41.76	46,427
	56,802,201.89	24,335,740	26,390,587	47,452,275		1,635,599

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.0   2.88

THE POTOMAC EDISON COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 30-R0.5
NET SALVAGE PERCENT.. -40

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1966	26,215.33	34,353	22,345	14,356	1.92	7,477
1967	13,724.01	17,689	11,506	7,708	2.38	3,239
1968	33,299.17	42,221	27,463	19,156	2.83	6,769
1969	23,854.83	29,768	19,363	14,034	3.26	4,305
1970	16,811.88	20,649	13,431	10,106	3.68	2,746
1971	7,076.82	8,553	5,563	4,345	4.10	1,060
1972	32,952.90	39,214	25,507	20,627	4.50	4,584
1973	24,712.67	28,947	18,829	15,769	4.90	3,218
1974	12,294.21	14,171	9,218	7,994	5.30	1,508
1975	11,544.00	13,091	8,515	7,647	5.70	1,342
1976	9,337.57	10,415	6,774	6,299	6.10	1,033
1977	15,907.68	17,453	11,352	10,919	6.49	1,682
1978	6,706.70	7,233	4,705	4,684	6.89	680
1979	13,315.88	14,112	9,179	9,463	7.29	1,298
1980	42,591.34	44,343	28,843	30,785	7.69	4,003
1981	18,228.08	18,629	12,117	13,402	8.10	1,655
1982	46,927.20	47,062	30,612	35,086	8.51	4,123
1983	24,625.43	24,213	15,749	18,727	8.93	2,097
1984	38,073.98	36,690	23,865	29,439	9.35	3,149
1985	43,076.82	40,667	26,452	33,856	9.77	3,465
1986	29,585.22	27,323	17,772	23,647	10.21	2,316
1987	8,662.35	7,822	5,088	7,039	10.65	661
1988	8,253.80	7,284	4,738	6,817	11.09	615
1989	14,941.20	12,864	8,367	12,551	11.55	1,087
1990	7,944.02	6,669	4,338	6,784	12.01	565
1991	21,569.24	17,635	11,471	18,726	12.48	1,500
1992	6,519.20	5,187	3,374	5,753	12.95	444
1993	9,120.15	7,048	4,584	8,184	13.44	609
1994	11,542.45	8,656	5,630	10,529	13.93	756
1995	3,116.27	2,264	1,473	2,890	14.43	200
1996	9,632.96	6,774	4,406	9,080	14.93	608
1997	238.97	162	105	230	15.45	15
1998	104,113.25	68,167	44,340	101,419	15.97	6,351
1999	92.63	58	38	92	16.50	6
2000	19,509.70	11,799	7,675	19,639	17.04	1,153
2001	229,444.18	132,986	86,502	234,720	17.58	13,352
2003	3,292.21	1,738	1,130	3,479	18.69	186
2004	3,919.88	1,966	1,279	4,209	19.25	219
2005	17,892.61	8,500	5,529	19,521	19.82	985
2006	588.70	264	172	652	20.39	32
2007	23,249.73	9,797	6,373	26,177	20.97	1,248
2008	247,902.43	97,757	63,587	283,476	21.55	13,154
2009	27,317.07	10,020	6,518	31,726	22.14	1,433

THE POTOMAC EDISON COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 30-R0.5
NET SALVAGE PERCENT.. -40

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2010	106,873.86	36,258	23,584	126,039	22.73	5,545
2011	302,423.70	94,277	61,323	362,070	23.32	15,526
2012	2,371.54	673	438	2,882	23.92	120
2013	14,520.85	3,720	2,420	17,909	24.51	731
2014	83,158.70	18,977	12,343	104,079	25.11	4,145
2015	56,616.95	11,309	7,356	71,908	25.72	2,796
2016	31,141.74	5,348	3,479	40,119	26.32	1,524
2017	19,130.97	2,741	1,783	25,000	26.93	928
2018	22,106.96	2,538	1,651	29,299	27.54	1,064
2019	39,878.17	3,443	2,239	53,590	28.15	1,904
2020	35,399.12	2,048	1,332	48,227	28.76	1,677
2021	170,525.77	4,935	3,210	235,526	29.38	8,017
2022	11,449.09	85	55	15,974	29.84	535
	2,165,322.14	1,148,565	747,090	2,284,361		151,440

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.1 6.99

THE POTOMAC EDISON COMPANY

ACCOUNT 373.10 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

SURVIVOR CURVE.. IOWA 44-S0.5
NET SALVAGE PERCENT.. -45

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1945	530.06	702	688	81	3.80	21
1953	1,267.86	1,568	1,536	302	6.48	47
1954	1,314.23	1,610	1,577	329	6.82	48
1955	877.32	1,065	1,043	229	7.16	32
1956	1,318.89	1,586	1,554	358	7.51	48
1957	405.56	483	473	115	7.85	15
1959	148.29	173	169	46	8.55	5
1960	4,039.12	4,672	4,577	1,280	8.90	144
1961	183.27	210	206	60	9.25	6
1962	141.68	161	158	47	9.61	5
1963	1,140.62	1,279	1,253	401	9.97	40
1964	192.65	214	210	69	10.33	7
1965	267.87	294	288	100	10.70	9
1966	28,023.49	30,411	29,791	10,843	11.07	979
1967	27,884.01	29,920	29,310	11,122	11.44	972
1968	28,764.24	30,504	29,882	11,826	11.82	1,001
1969	23,448.46	24,573	24,072	9,928	12.20	814
1970	14,004.11	14,500	14,204	6,102	12.58	485
1971	40,110.71	41,017	40,181	17,980	12.97	1,386
1972	29,705.99	29,995	29,384	13,690	13.36	1,025
1973	54,938.79	54,749	53,633	26,028	13.76	1,892
1974	52,831.79	51,953	50,894	25,712	14.16	1,816
1975	55,293.70	53,645	52,552	27,624	14.56	1,897
1976	26,639.25	25,485	24,966	13,661	14.97	913
1977	53,698.36	50,629	49,597	28,266	15.39	1,837
1978	53,783.99	49,965	48,947	29,040	15.81	1,837
1979	37,091.77	33,932	33,240	20,543	16.24	1,265
1980	77,000.35	69,351	67,937	43,714	16.67	2,622
1981	55,375.76	49,071	48,071	32,224	17.11	1,883
1982	61,314.10	53,445	52,356	36,549	17.55	2,083
1983	48,353.29	41,430	40,585	29,527	18.00	1,640
1984	58,104.21	48,904	47,907	36,344	18.46	1,969
1985	84,378.58	69,711	68,290	54,059	18.93	2,856
1986	135,709.32	110,017	107,774	89,005	19.40	4,588
1987	97,331.79	77,365	75,788	65,343	19.88	3,287
1988	199,207.65	155,191	152,028	136,823	20.36	6,720
1989	250,124.97	190,738	186,850	175,831	20.86	8,429
1990	172,187.78	128,469	125,850	123,822	21.36	5,797
1991	400,612.06	292,157	286,202	294,685	21.87	13,474
1992	331,698.71	236,220	231,405	249,558	22.39	11,146
1993	443,869.69	308,348	302,063	341,548	22.92	14,902
1994	448,716.20	303,731	297,540	353,098	23.46	15,051
1995	607,702.32	400,332	392,172	488,996	24.01	20,366

THE POTOMAC EDISON COMPANY

ACCOUNT 373.10 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 44-S0.5						
NET SALVAGE PERCENT.. -45						
1996	551,979.75	353,436	346,232	454,139	24.57	18,483
1997	1,426,809.01	886,802	868,725	1,200,148	25.14	47,739
1998	1,926,769.80	1,160,691	1,137,031	1,656,785	25.72	64,416
1999	39,686.74	23,136	22,664	34,882	26.31	1,326
2000	309,954.60	174,565	171,007	278,427	26.91	10,347
2001	2,804,611.74	1,522,242	1,491,212	2,575,475	27.53	93,552
2002	137,986.85	72,075	70,606	129,475	28.15	4,599
2003	112,173.02	56,225	55,079	107,572	28.79	3,736
2004	83,541.94	40,057	39,240	81,896	29.45	2,781
2005	117,059.23	53,582	52,490	117,246	30.11	3,894
2006	225,217.39	98,045	96,046	230,519	30.79	7,487
2007	646,657.28	266,594	261,160	676,493	31.49	21,483
2008	1,590,374.45	618,435	605,829	1,700,214	32.20	52,802
2009	338,019.73	123,311	120,797	369,332	32.93	11,216
2010	2,073,595.14	705,886	691,497	2,315,216	33.67	68,762
2011	5,399,003.36	1,704,511	1,669,766	6,158,789	34.42	178,931
2012	854,765.12	247,882	242,829	996,580	35.20	28,312
2013	617,115.89	162,902	159,582	735,236	35.99	20,429
2014	698,792.88	165,808	162,428	850,822	36.80	23,120
2015	1,141,356.99	239,590	234,706	1,420,262	37.63	37,743
2016	838,710.76	152,564	149,454	1,066,677	38.48	27,720
2017	865,476.03	132,911	130,202	1,124,738	39.34	28,590
2018	848,721.28	105,442	103,293	1,127,353	40.23	28,023
2019	1,044,014.86	98,398	96,392	1,417,430	41.14	34,454
2020	1,175,386.54	74,751	73,227	1,631,083	42.07	38,771
2021	1,145,187.49	36,980	36,227	1,624,295	43.02	37,757
2022	533,656.40	4,395	4,305	769,497	43.75	17,589
	31,556,357.13	12,350,991	12,099,229	33,657,489		1,049,421

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.1   3.33

THE POTOMAC EDISON COMPANY

ACCOUNT 389.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 75-R3						
NET SALVAGE PERCENT.. 0						
2005	3,778.48	827	859	2,920	58.58	50
	3,778.48	827	859	2,920		50

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 58.4 1.32

THE POTOMAC EDISON COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 60-R2						
NET SALVAGE PERCENT.. -15						
1911	38,668.75	44,247	44,469			
1920	9,845.61	10,854	11,322			
1941	1,653.26	1,629	1,901			
1953	1,162.16	1,053	1,336			
1955	4,274.73	3,809	4,916			
1956	4,668.83	4,124	5,369			
1957	24.58	22	28			
1958	300,339.19	260,365	345,390			
1959	5,938.00	5,096	6,829			
1963	494.79	407	553	16	17.08	1
1965	403,662.54	324,405	440,437	23,775	18.07	1,316
1966	37,967.07	30,141	40,922	2,740	18.58	147
1967	160,516.33	125,832	170,839	13,755	19.10	720
1968	313.87	243	330	31	19.63	2
1969	4,956.08	3,783	5,136	563	20.17	28
1973	51,507.04	37,090	50,356	8,877	22.43	396
1974	97,601.93	69,178	93,921	18,321	23.02	796
1977	19,915.67	13,425	18,227	4,676	24.83	188
1978	21,136.90	13,993	18,998	5,309	25.46	209
1979	32,599.18	21,188	28,766	8,723	26.09	334
1980	244,857.83	156,140	211,988	69,599	26.73	2,604
1981	58,772.42	36,734	49,873	17,715	27.39	647
1982	11,568.71	7,087	9,622	3,682	28.04	131
1983	19,601.15	11,755	15,959	6,582	28.71	229
1984	67,308.39	39,490	53,615	23,790	29.39	809
1985	126,025.40	72,295	98,153	46,776	30.07	1,556
1986	237,695.32	133,211	180,857	92,493	30.76	3,007
1987	726,440.54	397,378	539,511	295,896	31.46	9,405
1988	2,359,460.61	1,258,547	1,708,699	1,004,681	32.17	31,230
1989	1,208,748.08	628,307	853,037	537,023	32.88	16,333
1990	1,715,638.00	867,777	1,178,160	794,824	33.61	23,648
1991	1,050,006.97	516,608	701,386	506,122	34.33	14,743
1992	1,011,394.30	483,269	656,123	506,980	35.07	14,456
1993	908,371.68	420,985	571,561	473,066	35.82	13,207
1994	227,320.87	102,084	138,597	122,822	36.57	3,359
1995	280,870.13	122,094	165,764	157,237	37.32	4,213
1996	22,147.88	9,301	12,628	12,842	38.09	337
1997	125,276.70	50,760	68,916	75,152	38.86	1,934
1998	333,021.74	129,955	176,437	206,538	39.64	5,210
1999	102,467.31	38,454	52,208	65,629	40.42	1,624
2000	138,129.55	49,747	67,540	91,309	41.21	2,216
2001	1,810,011.58	624,100	847,325	1,234,188	42.01	29,378
2002	819,274.78	269,931	366,479	575,687	42.81	13,447

THE POTOMAC EDISON COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 60-R2						
NET SALVAGE PERCENT.. -15						
2003	6,426.71	2,018	2,740	4,651	43.62	107
2004	477,453.38	142,484	193,447	355,624	44.43	8,004
2005	38,844.06	10,981	14,909	29,762	45.25	658
2006	404,591.13	107,945	146,554	318,726	46.08	6,917
2007	412,482.86	103,490	140,506	333,849	46.91	7,117
2008	180,274.08	42,328	57,468	149,847	47.75	3,138
2009	649,117.41	141,959	192,734	553,751	48.59	11,396
2010	21,925.94	4,438	6,025	19,190	49.44	388
2011	289,354.72	53,850	73,111	259,647	50.29	5,163
2012	2,144,343.10	363,734	493,833	1,972,162	51.15	38,556
2013	263,507.52	40,303	54,718	248,316	52.02	4,773
2014	502,789.16	68,616	93,158	485,050	52.88	9,173
2015	746,600.13	89,293	121,231	737,359	53.76	13,716
2016	2,964,558.39	304,548	413,477	2,995,765	54.64	54,827
2017	454,557.99	39,033	52,994	469,748	55.52	8,461
2018	1,422,897.66	97,902	132,919	1,503,413	56.41	26,652
2019	967,379.64	50,062	67,968	1,044,519	57.30	18,229
2020	558,979.55	19,394	26,331	616,495	58.19	10,595
2021	30,575.90	527	716	34,446	59.10	583
2022	60,248.17	265	360	68,926	59.77	1,153
	27,398,563.95	9,080,063	12,299,682	19,208,667		427,466

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.9   1.56

THE POTOMAC EDISON COMPANY

ACCOUNT 391.00 OFFICE FURNITURE AND EQUIPMENT - OFFICE FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
1992	144,687.53	144,688	144,688			
1993	138,901.64	138,902	138,902			
1994	130,991.64	130,992	130,992			
1995	14,508.85	14,509	14,509			
1996	175,869.48	175,869	175,869			
1997	151,171.18	151,171	151,171			
1998	172,940.19	172,940	172,940			
1999	232,412.65	232,413	232,413			
2000	449,917.78	449,918	449,918			
2001	119,484.80	119,485	119,485			
2002	5,239.43	5,239	5,239			
2003	3,043.52	2,891	376	2,668	1.00	2,668
2010	15,369.75	9,222	1,200	14,170	8.00	1,771
2011	51,623.98	28,393	3,694	47,930	9.00	5,326
2012	819,236.78	409,618	53,291	765,946	10.00	76,595
2013	48,782.87	21,952	2,856	45,927	11.00	4,175
2015	4,726.10	1,654	215	4,511	13.00	347
2016	172,197.07	51,659	6,721	165,476	14.00	11,820
2017	75,916.21	18,979	2,469	73,447	15.00	4,896
2020	3,036.00	304	40	2,996	18.00	166
2021	1,545.92	77	10	1,536	19.00	81
2022	921.93	12	1	921	19.75	47
	2,932,525.30	2,280,887	1,806,999	1,125,526		107,892

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.4 3.68

THE POTOMAC EDISON COMPANY

ACCOUNT 391.15 OFFICE FURNITURE AND EQUIPMENT - OFFICE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
1992	92,657.35	92,657	92,657			
1993	2,616.48	2,616	2,616			
1994	14,762.75	14,763	14,763			
1995	10,305.09	10,305	10,305			
1996	87,870.26	87,870	87,870			
1997	37,263.00	37,263	37,263			
1998	29,948.34	29,948	29,948			
1999	1,954.26	1,954	1,954			
2004	11,088.74	11,089	11,090			
	288,466.27	288,465	288,466			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

THE POTOMAC EDISON COMPANY

ACCOUNT 391.20 OFFICE FURNITURE AND EQUIPMENT - PERSONAL COMPUTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
2007	1,450.37	1,450	1,450			
2012	21,361.90	21,362	21,362			
2013	11,787.75	10,609	2,232	9,556	1.00	9,556
2014	292,991.31	234,393	49,319	243,672	2.00	121,836
2015	236,568.34	165,598	34,844	201,724	3.00	67,241
2016	79,812.72	47,888	10,076	69,737	4.00	17,434
2017	102,918.30	51,459	10,828	92,090	5.00	18,418
2018	101,015.72	40,406	8,502	92,514	6.00	15,419
2019	572,532.56	171,760	36,140	536,393	7.00	76,628
2020	1,214,927.06	242,985	51,126	1,163,801	8.00	145,475
2021	159,219.69	15,922	3,350	155,870	9.00	17,319
2022	36,170.83	904	190	35,980	9.75	3,690
	2,830,756.55	1,004,736	229,419	2,601,337		493,016

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.3   17.42

THE POTOMAC EDISON COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 13-L2						
NET SALVAGE PERCENT.. +20						
1987	58,919.69	45,758	47,136			
1989	228,694.96	172,824	182,956			
1990	196,069.35	146,117	156,855			
1991	40,036.61	29,393	32,029			
2003	347,301.90	201,330	277,842			
2004	8,496.99	4,795	6,798			
2005	107,854.93	59,204	86,284			
2009	42,698.00	20,863	34,158			
2012	130,867.46	57,582	104,694			
2013	53,705.53	22,507	42,964			
2014	389,562.57	153,428	298,793	12,857	6.60	1,948
2015	213,568.14	77,411	150,754	20,101	7.11	2,827
2016	51,502.56	16,702	32,526	8,676	7.73	1,122
2017	392,578.98	109,922	214,068	99,995	8.45	11,834
2018	19,290.33	4,440	8,647	6,785	9.26	733
2019	1,160,951.80	205,043	399,311	529,450	10.13	52,266
2020	468,981.59	56,567	110,162	265,023	11.04	24,006
2021	391,828.48	23,870	46,485	266,978	12.01	22,230
2022	125,567.19	1,932	3,763	96,691	12.75	7,584
	4,428,477.06	1,409,688	2,236,225	1,306,557		124,550

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.5   2.81

THE POTOMAC EDISON COMPANY

ACCOUNT 393.00 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
1992	5,974.08	5,974	5,974			
1993	44,689.40	44,689	44,689			
1994	14,283.10	14,283	14,283			
1995	6,620.85	6,621	6,621			
2000	28,942.21	28,942	28,942			
2001	23,972.98	23,973	23,973			
2002	6,046.78	6,047	6,047			
2017	17,342.10	4,336	1,414	15,928	15.00	1,062
2019	14,277.70	2,142	699	13,579	17.00	799
2020	48.50	5	2	46	18.00	3
2021	24.71	1		25	19.00	1
2022	14.72		0	15	19.75	1
	162,237.13	137,013	132,644	29,593		1,866

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.9   1.15

THE POTOMAC EDISON COMPANY

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
1965	933.62	934	934			
1977	1,386.42	1,386	1,386			
1984	587.39	587	587			
1986	5,711.73	5,712	5,712			
1987	94,551.71	94,552	94,552			
1988	18,065.90	18,066	18,066			
1992	60,645.45	60,645	60,645			
1993	98,393.94	98,394	98,394			
1994	76,097.16	76,097	76,097			
1995	72,807.18	72,807	72,807			
1996	19,516.57	19,517	19,517			
1997	82,411.35	82,411	82,411			
1998	74,260.31	74,260	74,260			
1999	120,048.40	120,048	120,048			
2000	245,200.00	245,200	245,200			
2001	240,962.37	240,962	240,962			
2002	93,393.84	93,394	93,394			
2003	103,500.76	98,326	91,809	11,692	1.00	11,692
2004	16,078.30	14,470	13,511	2,567	2.00	1,284
2005	319,904.61	271,919	253,896	66,009	3.00	22,003
2006	110,262.83	88,210	82,363	27,900	4.00	6,975
2007	26,978.38	20,234	18,893	8,085	5.00	1,617
2008	474,248.40	331,974	309,970	164,278	6.00	27,380
2009	52,260.29	33,969	31,717	20,543	7.00	2,935
2010	53,441.72	32,065	29,940	23,502	8.00	2,938
2011	36,874.20	20,281	18,937	17,937	9.00	1,993
2012	1,273,222.13	636,611	594,415	678,807	10.00	67,881
2014	1,358,602.80	543,441	507,420	851,183	12.00	70,932
2015	19,207.55	6,723	6,277	12,931	13.00	995
2016	162,710.46	48,813	45,578	117,132	14.00	8,367
2017	535,899.60	133,975	125,095	410,805	15.00	27,387
2018	707,050.69	141,410	132,037	575,014	16.00	35,938
2019	39,165.04	5,875	5,486	33,679	17.00	1,981
2020	248,492.84	24,849	23,202	225,291	18.00	12,516
2021	716,955.42	35,848	33,471	683,484	19.00	35,973
2022	1,689,033.46	21,113	19,713	1,669,320	19.75	84,523
	9,248,862.82	3,815,078	3,648,702	5,600,161		425,310

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.2 4.60

THE POTOMAC EDISON COMPANY

ACCOUNT 395.00 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
1992	14,917.73	14,918	14,918			
1993	43,749.36	43,749	43,749			
1994	119,393.10	119,393	119,393			
1995	142,907.96	142,908	142,908			
1996	11,683.59	11,684	11,684			
1997	6,062.10	6,062	6,062			
1998	56,555.34	56,555	56,555			
2004	44,007.52	39,607	41,786	2,222	2.00	1,111
2005	37,856.44	32,178	33,948	3,908	3.00	1,303
2007	8,080.93	6,061	6,394	1,687	5.00	337
2008	191,900.59	134,330	141,719	50,182	6.00	8,364
2010	10,470.35	6,282	6,628	3,842	8.00	480
2012	39,393.46	19,697	20,780	18,613	10.00	1,861
2021	3.00		0	3	19.00	
	726,981.47	633,424	646,524	80,457		13,456

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.0   1.85

THE POTOMAC EDISON COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-S0.5						
NET SALVAGE PERCENT.. +5						
1987	34,948.48	30,329	33,201			
1988	16,086.55	13,708	15,282			
1989	395,850.64	330,931	376,058			
1990	101,018.50	82,868	95,968			
1992	42,051.15	33,137	39,949			
2005	4,137.27	2,256	3,930			
2012	126,309.90	46,618	119,994			
2013	7,821.55	2,656	7,430			
2015	101,796.87	28,093	96,707			
2017	14,023.84	2,898	13,323			
2020	345.84	31	329			
2021	176.12	8	167			
2022	105.04	1	3,673	3,573-		
	844,671.75	573,534	806,011	3,573-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

THE POTOMAC EDISON COMPANY

ACCOUNT 397.00 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
1990	84,958.81	84,959	84,959			
1991	21,379.33	21,379	21,379			
1992	37,457.57	37,458	37,458			
1993	51,885.80	51,886	51,886			
1994	8,347.25	8,347	8,347			
1995	87,269.38	87,269	87,269			
1998	33,293.37	33,293	33,293			
1999	2,060.16	2,060	2,060			
2000	65,311.97	65,312	65,312			
2001	99,815.00	99,815	99,815			
2002	49,195.49	49,195	49,195			
2003	4,836.00	4,836	4,836			
2004	8,242.04	8,242	8,242			
2008	75,617.37	75,617	75,617			
2009	397,467.73	397,468	397,468			
2010	2,478,361.02	2,478,361	2,478,361			
2011	1,478,630.89	1,478,631	1,478,631			
2012	570,414.87	570,415	570,415			
2013	2,653,945.70	2,388,551	2,653,946			
2014	106,904.71	85,524	95,944	10,961	2.00	5,480
2016	105,791.73	63,475	71,208	34,584	4.00	8,646
2017	62,515.01	31,258	35,066	27,449	5.00	5,490
2018	2,235,835.15	894,334	1,003,295	1,232,540	6.00	205,423
2019	4,426,833.25	1,328,050	1,489,852	2,936,981	7.00	419,569
2020	1,799,077.31	359,815	403,653	1,395,424	8.00	174,428
2021	1,244,022.68	124,402	139,559	1,104,464	9.00	122,718
2022	316,697.52	7,917	8,881	307,816	9.75	31,571
	18,506,167.11	10,837,869	11,455,947	7,050,220		973,325

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.2   5.26

THE POTOMAC EDISON COMPANY

ACCOUNT 398.00 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
1998	3,699.67	3,700	3,700			
2000	6,746.94	6,747	6,747			
2001	14,653.26	14,653	14,653			
2002	2,782.47	2,782	2,782			
2004	19,003.28	19,003	19,003			
2007	48,706.43	48,706	48,706			
2008	60,040.71	56,038	59,372	669	1.00	669
2010	5,452.80	4,362	4,622	831	3.00	277
	161,085.56	155,991	159,585	1,501		946

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.6 0.59

APPENDIX

SUMMARY OF PRESENT VALUE RESULTS

THE POTOMAC EDISON COMPANY
SUMMARY OF SURVIVOR CURVE, NET SALVAGE PERCENTS AND CALCULATED REMAINING LIFE ACCRUALS
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022
SFAS 143 METHOD - 5.93% DISCOUNT RATE

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF JUNE 30, 2022	NET SALVAGE ACCRUAL AMOUNT	BOOK DEPRECIATION RESERVE	THEORETICAL RESERVE - NET SALVAGE	BOOK RESERVE NO NET SALVAGE	NET PLANT	COMPOSITE REMAINING LIFE	REM. LIFE ANNUAL ACCRUAL PLANT ONLY	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(6)-(7)	(9)=(4)-(8)	(10)	(11)=(9)/(10)	(12)=(5)+(11)	(13)=(12)/(4)
	ELECTRIC PLANT												
	INTANGIBLE PLANT												
303.00	MISCELLANEOUS INTANGIBLE PLANT	7-SQ	0	25,518,930.61	-	18,333,018	-	18,333,018	7,185,913	3.9	1,839,674	1,839,674	7.21
	TOTAL INTANGIBLE PLANT			**25,518,930.61**	**-**	**18,333,018**	**-**	**18,333,018**	**7,185,913**		**1,839,674**	**1,839,674**	**7.21**
	DISTRIBUTION PLANT												
360.20	LAND AND LAND RIGHTS - EASEMENTS	75-R3	0	10,999,110.61	-	3,156,497	-	3,156,497	7,842,614	54.8	143,090	143,090	1.30
361.00	STRUCTURES AND IMPROVEMENTS	65-S4	(15)	11,344,560.25	16,069	5,716,535	221,556	5,494,979	5,849,581	45.7	127,932	144,001	1.27
362.00	STATION EQUIPMENT	65-R2.5	(15)	186,933,531.24	184,394	70,335,515	2,214,480	68,121,035	118,812,497	50.6	2,347,729	2,532,124	1.35
364.00	POLES, TOWERS AND FIXTURES	70-R4	(125)	131,651,738.90	881,958	70,244,646	12,061,384	58,183,262	73,468,476	48.9	1,502,268	2,384,226	1.81
365.00	OVERHEAD CONDUCTORS AND DEVICES	65-R1	(100)	151,495,917.54	680,053	40,460,712	6,845,024	33,615,689	117,880,229	49.4	2,386,673	3,066,725	2.02
365.10	OVERHEAD CONDUCTORS AND DEVICES - CLEARING	70-R4	0	77,713,677.02	-	16,600,546	-	16,600,546	61,113,131	63.1	969,012	969,012	1.25
366.00	UNDERGROUND CONDUIT	65-R4	(50)	66,754,673.86	196,862	29,932,474	2,571,263	27,361,211	39,393,463	44.6	883,508	1,080,369	1.62
367.00	UNDERGROUND CONDUCTORS AND DEVICES	46-R2.5	(50)	300,720,151.63	2,031,169	95,460,244	21,255,160	74,205,084	226,515,068	29.5	7,688,758	9,719,926	3.23
368.00	LINE TRANSFORMERS	51-R1.5	(35)	204,527,694.80	726,215	101,500,754	8,051,063	93,449,690	111,078,004	36.8	3,021,445	3,747,659	1.83
369.00	SERVICES	65-R4	(125)	73,021,590.19	663,050	53,923,896	9,189,094	44,734,802	28,286,788	42.9	659,591	1,322,641	1.81
370.00	METERS	42-R2.5	(30)	56,802,201.89	274,834	26,390,587	3,009,598	23,380,989	33,421,213	29.0	1,151,972	1,426,806	2.51
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	30-R0.5	(40)	2,165,322.14	24,674	747,090	234,085	513,005	1,652,317	15.1	109,539	134,213	6.20
373.10	STREET LIGHTING AND SIGNAL SYSTEMS	44-S0.5	(45)	31,556,357.13	168,932	12,099,229	1,595,370	10,503,859	21,052,498	32.1	656,405	825,337	2.62
	TOTAL DISTRIBUTION PLANT			**1,305,686,527.20**	**5,848,209**	**526,568,725**	**67,248,078**	**459,320,647**	**846,365,880**		**21,647,921**	**27,496,130**	**2.11**
	GENERAL PLANT												
389.20	LAND RIGHTS	75-R3	0	3,778.48	-	859	-	859	2,920	58.4	50	50	1.32
390.10	STRUCTURES AND IMPROVEMENTS	60-R2	(15)	27,398,563.95	27,776	12,299,682	339,691	11,959,991	15,438,573	44.9	343,567	371,343	1.36
391.00	OFFICE FURNITURE AND EQUIPMENT - OFFICE FURNITURE	20-SQ	0	2,932,525.30	-	1,806,999	-	1,806,999	1,125,526	10.4	107,892	107,892	3.68
391.15	OFFICE FURNITURE AND EQUIPMENT - OFFICE EQUIPMENT	10-SQ	0	288,466.27	-	288,466	-	288,466	-	-	-	- *	-
391.20	OFFICE FURNITURE AND EQUIPMENT - PERSONAL COMPUTERS	10-SQ	0	2,830,756.55	-	229,419	-	229,419	2,601,337	5.3	493,016	493,016	17.42
392.00	TRANSPORTATION EQUIPMENT	13-L2	20	4,428,477.06	(66,430)	2,236,225	(324,754)	2,560,979	1,867,498	10.5	178,023	111,593	2.52
393.00	STORES EQUIPMENT	20-SQ	0	162,237.13	-	132,644	-	132,644	29,593	15.9	1,866	1,866	1.15
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	20-SQ	0	9,248,862.82	-	3,648,702	-	3,648,702	5,600,161	13.2	425,310	425,310	4.60
395.00	LABORATORY EQUIPMENT	20-SQ	0	726,981.47	-	646,524	-	646,524	80,457	6.0	13,456	13,456	1.85
396.00	POWER OPERATED EQUIPMENT	20-S0.5	5	844,671.75	(2,538)	806,011	(27,748)	833,758	10,913	-	-	(2,538) **	(0.30)
397.00	COMMUNICATION EQUIPMENT	10-SQ	0	18,506,167.11	-	11,455,947	-	11,455,947	7,050,220	7.2	973,325	973,325	5.26
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	0	161,085.56	-	159,585	-	159,585	1,501	1.6	947	947	0.59
	TOTAL GENERAL PLANT			**67,532,573.45**	**(41,193)**	**33,711,063**	**(12,811)**	**33,723,875**	**33,808,699**		**2,537,452**	**2,496,259**	**3.70**
	TOTAL DEPRECIABLE PLANT			**1,398,738,031.26**	**5,807,016**	**578,612,806**	**67,235,266**	**511,377,540**	**887,360,492**		**26,025,047**	**31,832,063**	**2.28**
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED												
301.00	ORGANIZATION			124,448.78									
360.10	LAND AND LAND RIGHTS - LAND			11,931,025.07									
389.10	LAND AND LAND RIGHTS - LAND			1,382,979.33									
399.10	ASSET RETIREMENT COSTS - GENERAL PLANT			14,235.89		11,197							
	TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED			**13,452,689.07**		**11,197**							
	TOTAL ELECTRIC PLANT			**1,412,190,720.33**		**578,624,003**							

* FOR NEW ADDITIONS TO ACCOUNT 391.15 OFFICE FURNITURE AND EQUIPMENT - OFFICE EQUIPMENT A 10.00% DEPRECIATION RATE IS RECOMMENDED BASED ON A 10-SQ AND 0 PERCENT NET SALVAGE
** FOR NEW ADDITIONS TO ACCOUNT 396.00 POWER OPERATED EQUIPMENT A 4.75% DEPRECIATION RATE IS RECOMMENDED BASED ON A 20-S0.5 SURVIVOR CURVE AND 5 PERCENT NET SALVAGE

NOTE: THE ANNUAL ACCRUAL RATE FOR NEW ADDITIONS AS OF JULY 1, 2022 ARE AS FOLLOWS:
ACCOUNT 363.00, ELECTRIC STORAGE BATTERY ACCRUAL RATE IS 6.67% BASED ON A 15-L3 SURVIVOR CURVE AND 0% NET SALVAGE
ACCOUNT 371.10, ELECTRIC VEHICLE CHARGING STATIONS ACCRUAL RATE IS 10.00% BASED ON A 10-S3 SURVIVOR CURVE AND 0% NET SALVAGE

DETAILED PRESENT VALUE CALCULATIONS

Account 303.00 Miscellaneous Intangible Plant
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
2012	4,065,813.52	0%	0	7	0	0	0.00	0.0593	0	0	-	0.3319	-	-
2013	3,319,463.95	0%	0	7	0	0	0.00	0.0593	0	0	-	0.3319	-	-
2014	999,423.57	0%	0	7	0	0	0.00	0.0593	0	0	-	0.3319	-	-
2015	1,146,068.99	0%	0	7	0	0	0.00	0.0593	0	0	-	0.3319	-	-
2016	1,436,850.15	0%	0	7	0	0	1.00	0.0560	0	0	-	0.2759	-	-
2017	1,627,201.29	0%	0	7	0	0	2.00	0.0528	0	0	-	0.2230	-	-
2018	5,255,955.54	0%	0	7	0	0	3.00	0.0499	0	0	-	0.1731	-	-
2019	3,362,807.35	0%	0	7	0	0	4.00	0.0471	0	0	-	0.1260	-	-
2020	2,695,896.65	0%	0	7	0	0	5.00	0.0445	0	0	-	0.0816	-	-
2021	995,109.46	0%	0	7	0	0	6.00	0.0420	0	0	-	0.0396	-	-
2022	614,340.14	0%	0	7	0	0	6.75	0.0402	0	0	-	0.0097	-	-
	25,518,930.61		-			-			-	-			-	-

Account 360.20 Land and Land Rights - Easements
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1945	127,639.47	0%	0	75	0	0	14.22	0.0261	0	0	-	0.4275	-	-
1953	258,623.23	0%	0	75	0	0	18.18	0.0208	0	0	-	0.3376	-	-
1954	31,794.44	0%	0	75	0	0	18.73	0.0202	0	0	-	0.3266	-	-
1955	45,324.46	0%	0	75	0	0	19.29	0.0195	0	0	-	0.3159	-	-
1956	19,528.59	0%	0	75	0	0	19.87	0.0189	0	0	-	0.3050	-	-
1957	17,168.80	0%	0	75	0	0	20.46	0.0182	0	0	-	0.2944	-	-
1958	76,754.87	0%	0	75	0	0	21.06	0.0176	0	0	-	0.2839	-	-
1959	52,861.82	0%	0	75	0	0	21.67	0.0170	0	0	-	0.2737	-	-
1960	9,919.21	0%	0	75	0	0	22.29	0.0164	0	0	-	0.2636	-	-
1961	79,869.77	0%	0	75	0	0	22.92	0.0158	0	0	-	0.2537	-	-
1962	47,576.87	0%	0	75	0	0	23.56	0.0153	0	0	-	0.2441	-	-
1963	55,071.15	0%	0	75	0	0	24.22	0.0147	0	0	-	0.2345	-	-
1964	38,812.46	0%	0	75	0	0	24.88	0.0141	0	0	-	0.2252	-	-
1965	32,530.21	0%	0	75	0	0	25.55	0.0136	0	0	-	0.2162	-	-
1966	48,367.86	0%	0	75	0	0	26.24	0.0131	0	0	-	0.2073	-	-
1967	80,671.70	0%	0	75	0	0	26.93	0.0126	0	0	-	0.1987	-	-
1968	76,766.98	0%	0	75	0	0	27.63	0.0121	0	0	-	0.1903	-	-
1969	29,966.67	0%	0	75	0	0	28.34	0.0116	0	0	-	0.1821	-	-
1970	68,076.58	0%	0	75	0	0	29.06	0.0111	0	0	-	0.1742	-	-
1971	65,784.35	0%	0	75	0	0	29.78	0.0107	0	0	-	0.1666	-	-
1972	239,923.05	0%	0	75	0	0	30.52	0.0102	0	0	-	0.1591	-	-
1973	26,447.98	0%	0	75	0	0	31.26	0.0098	0	0	-	0.1519	-	-
1974	34,581.39	0%	0	75	0	0	32.01	0.0094	0	0	-	0.1449	-	-
1975	20,556.27	0%	0	75	0	0	32.77	0.0090	0	0	-	0.1381	-	-
1976	22,446.30	0%	0	75	0	0	33.54	0.0086	0	0	-	0.1315	-	-
1977	31,589.74	0%	0	75	0	0	34.31	0.0082	0	0	-	0.1253	-	-
1978	30,131.51	0%	0	75	0	0	35.09	0.0079	0	0	-	0.1192	-	-
1979	15,591.98	0%	0	75	0	0	35.88	0.0075	0	0	-	0.1133	-	-
1980	80,977.96	0%	0	75	0	0	36.68	0.0072	0	0	-	0.1076	-	-
1981	133,961.66	0%	0	75	0	0	37.48	0.0068	0	0	-	0.1021	-	-
1982	85,874.00	0%	0	75	0	0	38.29	0.0065	0	0	-	0.0969	-	-
1983	39,101.68	0%	0	75	0	0	39.11	0.0062	0	0	-	0.0918	-	-
1984	28,701.03	0%	0	75	0	0	39.93	0.0059	0	0	-	0.0869	-	-
1985	39,963.23	0%	0	75	0	0	40.76	0.0057	0	0	-	0.0823	-	-
1986	42,954.73	0%	0	75	0	0	41.60	0.0054	0	0	-	0.0777	-	-
1987	19,810.30	0%	0	75	0	0	42.44	0.0051	0	0	-	0.0734	-	-
1988	23,699.91	0%	0	75	0	0	43.29	0.0049	0	0	-	0.0693	-	-
1989	39,871.50	0%	0	75	0	0	44.14	0.0047	0	0	-	0.0654	-	-
1990	66,872.81	0%	0	75	0	0	45.01	0.0044	0	0	-	0.0615	-	-
1991	123,777.04	0%	0	75	0	0	45.87	0.0042	0	0	-	0.0579	-	-
1992	53,917.66	0%	0	75	0	0	46.75	0.0040	0	0	-	0.0544	-	-
1993	19,617.26	0%	0	75	0	0	47.62	0.0038	0	0	-	0.0511	-	-
1994	22,697.40	0%	0	75	0	0	48.51	0.0036	0	0	-	0.0478	-	-
1995	695,096.71	0%	0	75	0	0	49.40	0.0034	0	0	-	0.0448	-	-
1996	101,055.79	0%	0	75	0	0	50.30	0.0033	0	0	-	0.0419	-	-
1997	172,774.99	0%	0	75	0	0	51.20	0.0031	0	0	-	0.0391	-	-
1998	271,304.17	0%	0	75	0	0	52.10	0.0029	0	0	-	0.0364	-	-
1999	10,542.15	0%	0	75	0	0	53.01	0.0028	0	0	-	0.0339	-	-
2000	144,263.08	0%	0	75	0	0	53.93	0.0027	0	0	-	0.0315	-	-
2001	17,573.59	0%	0	75	0	0	54.85	0.0025	0	0	-	0.0291	-	-
2003	138,199.40	0%	0	75	0	0	56.71	0.0023	0	0	-	0.0248	-	-
2004	39,388.75	0%	0	75	0	0	57.64	0.0021	0	0	-	0.0228	-	-
2005	599,503.49	0%	0	75	0	0	58.58	0.0020	0	0	-	0.0209	-	-
2007	1,040,277.74	0%	0	75	0	0	60.46	0.0018	0	0	-	0.0174	-	-
2008	1,055,295.22	0%	0	75	0	0	61.41	0.0017	0	0	-	0.0158	-	-
2010	1,685,990.40	0%	0	75	0	0	63.32	0.0015	0	0	-	0.0128	-	-
2011	1,032,285.12	0%	0	75	0	0	64.28	0.0015	0	0	-	0.0114	-	-
2012	290,672.10	0%	0	75	0	0	65.24	0.0014	0	0	-	0.0100	-	-
2020	1.00	0%	0	75	0	0	73.03	0.0009	0	0	-	0.0016	-	-
	9,800,399.58		-			-			-	-			-	-

Account 361.00 Structures and Improvements
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1950	2,283.85	-20%	457	65	11	0	6.83	0.0400	18	18	10	0.6511	297	307
1952	8,202.64	-20%	1,641	65	39	1	7.41	0.0387	63	64	34	0.6289	1,032	1,066
1953	7,122.83	-20%	1,425	65	34	1	7.72	0.0380	54	55	30	0.6173	879	909
1954	1,574.04	-20%	315	65	7	0	8.04	0.0373	12	12	7	0.6056	191	197
1955	2,607.32	-20%	521	65	12	0	8.37	0.0366	19	19	11	0.5938	310	320
1956	495.06	-20%	99	65	2	0	8.72	0.0359	4	4	2	0.5815	58	60
1957	79,494.63	-20%	15,899	65	376	6	9.09	0.0351	558	564	323	0.5687	9,042	9,365
1958	5,159.30	-20%	1,032	65	24	0	9.47	0.0344	35	36	21	0.5559	574	594
1959	6,687.89	-20%	1,338	65	32	0	9.88	0.0336	45	45	27	0.5423	725	752
1960	21,615.83	-20%	4,323	65	102	2	10.30	0.0328	142	143	86	0.5288	2,286	2,372
1961	46,479.75	-20%	9,296	65	220	3	10.74	0.0319	297	300	183	0.5150	4,787	4,971
1962	542.50	-20%	109	65	3	0	11.20	0.0311	3	3	2	0.5009	54	56
1963	5,057.50	-20%	1,012	65	24	0	11.68	0.0303	31	31	20	0.4866	492	512
1964	11,839.33	-20%	2,368	65	56	1	12.19	0.0294	70	70	45	0.4718	1,117	1,163
1965	738.45	-20%	148	65	3	0	12.71	0.0285	4	4	3	0.4572	68	70
1966	20,478.61	-20%	4,096	65	97	1	13.26	0.0276	113	115	77	0.4422	1,811	1,888
1967	16,751.91	-20%	3,350	65	79	1	13.84	0.0267	90	91	62	0.4269	1,430	1,493
1968	62,491.61	-20%	12,498	65	296	5	14.44	0.0258	323	327	230	0.4116	5,144	5,374
1969	2,833.73	-20%	567	65	13	0	15.06	0.0249	14	14	10	0.3963	225	235
1970	116,038.87	-20%	23,208	65	549	8	15.71	0.0240	557	565	416	0.3809	8,839	9,256
1971	61,579.33	-20%	12,316	65	291	4	16.38	0.0231	284	289	218	0.3656	4,502	4,720
1972	1,666.69	-20%	333	65	8	0	17.08	0.0222	7	8	6	0.3502	117	123
1973	8,849.05	-20%	1,770	65	42	1	17.81	0.0213	38	38	30	0.3348	593	623
1974	674.59	-20%	135	65	3	0	18.56	0.0204	3	3	2	0.3196	43	45
1975	135,648.10	-20%	27,130	65	642	10	19.33	0.0195	528	538	451	0.3047	8,267	8,718
1976	83,443.84	-20%	16,689	65	395	6	20.13	0.0186	310	316	272	0.2899	4,839	5,111
1977	121,789.69	-20%	24,358	65	576	9	20.95	0.0177	432	441	390	0.2755	6,710	7,100
1978	63,847.48	-20%	12,769	65	302	5	21.79	0.0169	216	220	201	0.2613	3,337	3,538
1979	13,159.73	-20%	2,632	65	62	1	22.65	0.0161	42	43	41	0.2476	652	692
1980	74,236.30	-20%	14,847	65	351	5	23.53	0.0153	227	232	224	0.2342	3,477	3,701
1981	173,571.73	-20%	34,714	65	821	13	24.43	0.0145	504	517	512	0.2211	7,677	8,189
1982	35,274.38	-20%	7,055	65	167	3	25.34	0.0138	97	100	102	0.2086	1,472	1,574
1983	2,105.70	-20%	421	65	10	0	26.27	0.0131	5	6	6	0.1965	83	89
1984	50,704.79	-20%	10,141	65	240	4	27.21	0.0124	125	129	139	0.1849	1,875	2,015
1985	387,179.03	-20%	77,436	65	1,831	28	28.16	0.0117	907	935	1,038	0.1738	13,459	14,497
1986	11,421.22	-20%	2,284	65	54	1	29.12	0.0111	25	26	30	0.1632	373	403
1987	26,541.46	-20%	5,308	65	126	2	30.09	0.0105	56	58	67	0.1530	812	880
1988	13,791.68	-20%	2,758	65	65	1	31.06	0.0099	27	28	34	0.1434	396	430
1989	52,993.65	-20%	10,599	65	251	4	32.05	0.0094	99	103	127	0.1342	1,422	1,549
1990	246,551.07	-20%	49,310	65	1,166	18	33.03	0.0088	436	454	573	0.1255	6,189	6,762
1991	92,671.75	-20%	18,534	65	438	7	34.02	0.0084	155	162	209	0.1172	2,173	2,382
1992	889,281.27	-20%	177,856	65	4,206	65	35.01	0.0079	1403	1,468	1,940	0.1094	19,462	21,402
1993	332,351.31	-20%	66,470	65	1,572	24	36.01	0.0074	495	519	701	0.1020	6,778	7,479
1994	1,008,542.02	-20%	201,708	65	4,770	73	37.01	0.0070	1418	1,492	2,054	0.0949	19,151	21,205
1995	689,934.43	-20%	137,987	65	3,263	50	38.00	0.0066	917	967	1,355	0.0884	12,194	13,549
1996	113,966.53	-20%	22,793	65	539	8	39.00	0.0063	143	151	216	0.0821	1,871	2,087
1998	340,345.48	-20%	68,069	65	1,610	25	41.00	0.0056	380	405	594	0.0706	4,805	5,399
2000	386,592.21	-20%	77,318	65	1,828	28	43.00	0.0050	385	413	619	0.0603	4,665	5,284
2001	31,824.63	-20%	6,365	65	151	2	44.00	0.0047	30	32	49	0.0556	354	403
2003	1,169,905.60	-20%	233,981	65	5,533	85	46.00	0.0042	980	1,065	1,617	0.0470	10,999	12,616
2004	28,610.63	-20%	5,722	65	135	2	47.00	0.0040	23	25	37	0.0431	246	284
2005	255,819.02	-20%	51,164	65	1,210	19	48.00	0.0037	191	210	316	0.0393	2,012	2,328
2006	197,711.71	-20%	39,542	65	935	14	49.00	0.0035	139	154	230	0.0358	1,415	1,645
2007	54,033.83	-20%	10,807	65	256	4	50.00	0.0033	36	40	59	0.0325	351	410
2008	1,011,054.43	-20%	202,211	65	4,782	74	51.00	0.0031	635	709	1,030	0.0293	5,930	6,959
2009	111,569.20	-20%	22,314	65	528	8	52.00	0.0030	66	74	106	0.0264	588	694
2010	701,575.54	-20%	140,315	65	3,318	51	53.00	0.0028	393	444	613	0.0236	3,306	3,918
2013	19,438.11	-20%	3,888	65	92	1	56.00	0.0024	9	11	13	0.0161	62	75
2015	40,278.62	-20%	8,056	65	190	3	58.00	0.0021	17	20	21	0.0117	95	115
2016	193,887.04	-20%	38,777	65	917	14	59.00	0.0020	77	91	85	0.0098	379	463
2017	87,812.46	-20%	17,562	65	415	6	60.00	0.0019	33	39	32	0.0079	139	171
2018	98,943.80	-20%	19,789	65	468	7	61.00	0.0018	35	42	29	0.0061	121	150
2019	333,954.57	-20%	66,791	65	1,579	24	62.00	0.0017	111	136	73	0.0045	298	371
2020	91,440.48	-20%	18,288	65	432	7	63.00	0.0016	29	35	13	0.0029	53	66
2021	1,079,386.76	-20%	215,877	65	5,105	79	64.00	0.0015	321	399	79	0.0014	303	381
2022	103.66	-20%	21	65	0	0	64.75	0.0014	0	0	0	0.0003	0	0
	11,344,560.25		2,268,912.05			825.41			15,243.39	16,068.80			203,403.68	221,555.87

Account 362.00 Station Equipment
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1940	9,640.98	-20%	1,928	65	46	1	9.51	0.0343	66	67	39	0.5545	1,069	1,108
1943	5,751.03	-20%	1,150	65	27	0	10.35	0.0327	38	38	23	0.5272	606	629
1946	3,052.69	-20%	611	65	14	0	11.27	0.0310	19	19	12	0.4988	305	316
1947	29,151.96	-20%	5,830	65	138	2	11.60	0.0304	177	179	113	0.4890	2,851	2,964
1949	63,815.53	-20%	12,763	65	302	5	12.28	0.0292	373	378	245	0.4693	5,989	6,234
1950	7,906.15	-20%	1,581	65	37	1	12.64	0.0286	45	46	30	0.4591	726	756
1951	69,471.01	-20%	13,894	65	329	5	13.02	0.0280	389	394	263	0.4487	6,234	6,497
1952	104,112.13	-20%	20,822	65	492	8	13.40	0.0274	571	578	391	0.4385	9,130	9,521
1953	65,240.02	-20%	13,048	65	309	5	13.80	0.0268	349	354	243	0.4279	5,584	5,827
1954	81,893.07	-20%	16,379	65	387	6	14.22	0.0261	428	434	303	0.4171	6,832	7,135
1955	54,999.34	-20%	11,000	65	260	4	14.64	0.0255	281	285	202	0.4066	4,473	4,674
1956	169,975.77	-20%	33,995	65	804	12	15.08	0.0249	846	858	617	0.3958	13,457	14,074
1957	102,653.57	-20%	20,531	65	485	7	15.53	0.0242	498	505	369	0.3851	7,906	8,276
1958	153,381.37	-20%	30,676	65	725	11	16.00	0.0236	724	735	547	0.3742	11,479	12,025
1959	256,208.47	-20%	51,242	65	1,212	19	16.48	0.0229	1,176	1,195	904	0.3633	18,618	19,522
1960	329,176.92	-20%	65,835	65	1,557	24	16.97	0.0223	1,469	1,493	1,150	0.3526	23,211	24,361
1961	286,104.78	-20%	57,221	65	1,353	21	17.47	0.0217	1,240	1,261	989	0.3419	19,563	20,552
1962	38,104.15	-20%	7,621	65	180	3	17.99	0.0210	160	163	130	0.3311	2,523	2,654
1963	114,576.17	-20%	22,915	65	542	8	18.53	0.0204	467	476	387	0.3202	7,338	7,725
1964	168,270.51	-20%	33,654	65	796	12	19.07	0.0198	665	677	562	0.3097	10,422	10,985
1965	66,964.57	-20%	13,393	65	317	5	19.63	0.0191	256	261	221	0.2991	4,006	4,227
1966	239,646.11	-20%	47,929	65	1,133	17	20.20	0.0185	888	905	781	0.2887	13,836	14,618
1967	255,809.78	-20%	51,162	65	1,210	19	20.78	0.0179	916	935	823	0.2784	14,245	15,068
1968	405,816.69	-20%	81,163	65	1,919	30	21.37	0.0173	1,405	1,435	1,288	0.2683	21,778	23,067
1969	436,900.46	-20%	87,380	65	2,066	32	21.97	0.0167	1,462	1,493	1,368	0.2584	22,580	23,948
1970	1,779,890.83	-20%	355,978	65	8,418	130	22.59	0.0161	5,745	5,875	5,492	0.2485	88,465	93,957
1971	543,554.34	-20%	108,711	65	2,571	40	23.21	0.0156	1,693	1,732	1,653	0.2390	25,978	27,631
1972	299,355.87	-20%	59,871	65	1,416	22	23.85	0.0150	899	920	896	0.2295	13,738	14,634
1973	775,480.67	-20%	155,096	65	3,667	56	24.50	0.0145	2,242	2,299	2,285	0.2202	34,145	36,430
1974	535,678.50	-20%	107,136	65	2,533	39	25.15	0.0139	1,492	1,531	1,553	0.2112	22,626	24,180
1975	938,734.10	-20%	187,747	65	4,440	68	25.82	0.0134	2,516	2,584	2,676	0.2023	37,982	40,658
1976	1,535,342.37	-20%	307,068	65	7,261	112	26.49	0.0129	3,959	4,070	4,302	0.1937	59,494	63,796
1977	1,610,099.30	-20%	322,020	65	7,615	117	27.18	0.0124	3,990	4,107	4,431	0.1853	59,662	64,093
1978	848,715.42	-20%	169,743	65	4,014	62	27.87	0.0119	2,021	2,083	2,293	0.1771	30,067	32,360
1979	730,435.21	-20%	146,087	65	3,454	53	28.58	0.0114	1,670	1,723	1,936	0.1691	24,701	26,637
1980	700,312.38	-20%	140,062	65	3,312	51	29.29	0.0110	1,537	1,588	1,820	0.1614	22,601	24,420
1981	734,783.11	-20%	146,957	65	3,475	53	30.01	0.0105	1,547	1,600	1,871	0.1538	22,609	24,479
1982	1,000,941.88	-20%	200,188	65	4,734	73	30.73	0.0101	2,021	2,094	2,496	0.1466	29,355	31,850
1983	1,344,679.90	-20%	268,936	65	6,359	98	31.47	0.0097	2,602	2,700	3,280	0.1395	37,524	40,805
1984	1,568,993.54	-20%	313,799	65	7,420	114	32.21	0.0093	2,910	3,024	3,743	0.1327	41,647	45,390
1985	3,170,882.80	-20%	634,177	65	14,996	231	32.96	0.0089	5,632	5,862	7,392	0.1261	79,974	87,366
1986	299,037.64	-20%	59,808	65	1,414	22	33.72	0.0085	508	530	681	0.1197	7,158	7,839
1987	657,344.64	-20%	131,469	65	3,109	48	34.49	0.0081	1,069	1,117	1,459	0.1135	14,918	16,377
1988	1,251,601.71	-20%	250,320	65	5,919	91	35.26	0.0078	1,947	2,038	2,708	0.1075	26,915	29,623
1989	4,757,670.32	-20%	951,534	65	22,500	346	36.04	0.0074	7,076	7,422	10,025	0.1018	96,827	106,852
1990	3,477,561.38	-20%	695,512	65	16,446	253	36.83	0.0071	4,942	5,195	7,128	0.0962	66,894	74,022
1991	3,700,768.94	-20%	740,154	65	17,502	269	37.63	0.0068	5,022	5,292	7,370	0.0908	67,193	74,563
1992	3,241,727.09	-20%	648,345	65	15,331	236	38.43	0.0065	4,201	4,437	6,267	0.0856	55,517	61,784
1993	1,908,304.68	-20%	381,661	65	9,025	139	39.23	0.0062	2,362	2,501	3,578	0.0807	30,803	34,381
1994	8,081,773.61	-20%	1,616,355	65	38,221	588	40.05	0.0059	9,541	10,129	14,671	0.0759	122,668	137,339
1995	5,220,997.51	-20%	1,044,200	65	24,692	380	40.87	0.0056	5,879	6,259	9,166	0.0713	74,450	83,617
1996	3,248,391.63	-20%	649,678	65	15,363	236	41.70	0.0054	3,487	3,723	5,507	0.0669	43,441	48,948
1997	409,823.49	-20%	81,965	65	1,938	30	42.53	0.0051	419	449	670	0.0626	5,134	5,804
1998	3,545,998.40	-20%	709,200	65	16,770	258	43.37	0.0049	3,457	3,715	5,581	0.0586	41,534	47,114
1999	787,452.51	-20%	157,491	65	3,724	57	44.22	0.0046	731	788	1,191	0.0546	8,605	9,795
2000	5,222,558.00	-20%	1,044,512	65	24,699	380	45.07	0.0044	4,617	4,997	7,573	0.0509	53,160	60,733
2001	2,715,863.66	-20%	543,173	65	12,844	198	45.93	0.0042	2,285	2,483	3,768	0.0473	25,687	29,456
2002	730,515.38	-20%	146,103	65	3,455	53	46.79	0.0040	585	638	968	0.0439	6,408	7,376
2003	2,695,764.67	-20%	539,153	65	12,749	196	47.66	0.0038	2,053	2,249	3,401	0.0406	21,869	25,270
2004	7,406,797.74	-20%	1,481,360	65	35,029	539	48.53	0.0036	5,365	5,904	8,876	0.0374	55,438	64,314
2005	6,192,694.63	-20%	1,238,539	65	29,287	451	49.41	0.0034	4,264	4,714	7,024	0.0344	42,612	49,636
2006	2,678,445.78	-20%	535,689	65	12,667	195	50.30	0.0033	1,752	1,947	2,865	0.0315	16,876	19,741
2007	3,807,344.70	-20%	761,469	65	18,006	277	51.18	0.0031	2,367	2,644	3,828	0.0288	21,913	25,741
2008	20,793,537.73	-20%	4,158,708	65	98,339	1,513	52.08	0.0030	12,275	13,788	19,547	0.0261	108,661	128,208
2009	6,457,259.06	-20%	1,291,452	65	30,538	470	52.98	0.0028	3,619	4,089	5,647	0.0236	30,496	36,143
2010	3,296,161.94	-20%	659,232	65	15,589	240	53.88	0.0027	1,754	1,994	2,667	0.0212	13,993	16,660
2011	1,315,598.87	-20%	263,120	65	6,222	96	54.78	0.0025	665	760	978	0.0190	4,988	5,967
2012	839,518.24	-20%	167,904	65	3,970	61	55.70	0.0024	402	463	568	0.0168	2,814	3,382
2013	5,028,130.10	-20%	1,005,626	65	23,780	366	56.61	0.0023	2,286	2,652	3,069	0.0147	14,778	17,848
2014	2,070,479.77	-20%	414,096	65	9,792	151	57.53	0.0022	893	1,044	1,125	0.0127	5,266	6,391
2015	74,087.90	-20%	14,818	65	350	5	58.45	0.0020	30	36	35	0.0108	161	196
2016	9,437,900.40	-20%	1,887,580	65	44,635	687	59.38	0.0019	3,659	4,345	3,859	0.0090	17,064	20,924
2017	5,265,034.23	-20%	1,053,007	65	24,900	383	60.31	0.0018	1,935	2,318	1,797	0.0073	7,724	9,521
2018	3,215,263.97	-20%	643,053	65	15,206	234	61.24	0.0017	1,120	1,354	880	0.0057	3,678	4,557
2019	8,462,656.34	-20%	1,692,531	65	40,022	616	62.17	0.0017	2,794	3,409	1,743	0.0042	7,087	8,829
2020	9,676,534.50	-20%	1,935,307	65	45,763	704	63.11	0.0016	3,026	3,730	1,331	0.0027	5,264	6,595
2021	8,232,991.60	-20%	1,646,598	65	38,936	599	64.06	0.0015	2,437	3,036	563	0.0013	2,167	2,730
2022	9,093,435.03	-20%	1,818,687	65	43,006	662	64.76	0.0014	2,586	3,247	159	0.0003	599	758
	186,933,531.24		37,386,706.25			13,600.99			170,793.08	184,394.08			1,996,088.54	2,214,480.08

Account 364 Poles, Towers and Fixtures
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1945	250,590.32	-125%	313,238	70	5,553	79	7.48	0.0385	12,072	12,152	4,960	0.6322	198,025	202,985
1953	1,120,183.68	-125%	1,400,230	70	24,824	355	10.72	0.0320	44,777	45,131	21,022	0.5215	730,261	751,283
1954	112,403.12	-125%	140,504	70	2,491	36	11.22	0.0311	4,365	4,401	2,092	0.5062	71,126	73,217
1955	194,470.11	-125%	243,088	70	4,310	62	11.75	0.0301	7,326	7,387	3,586	0.4905	119,225	122,812
1956	141,301.65	-125%	176,627	70	3,131	45	12.29	0.0292	5,160	5,204	2,582	0.4749	83,880	86,461
1957	144,510.04	-125%	180,638	70	3,202	46	12.86	0.0283	5,106	5,152	2,614	0.4590	82,910	85,524
1958	281,354.97	-125%	351,694	70	6,235	89	13.45	0.0273	9,610	9,699	5,037	0.4431	155,819	160,856
1959	384,573.30	-125%	480,717	70	8,522	122	14.06	0.0264	12,682	12,803	6,811	0.4271	205,334	212,145
1960	218,353.28	-125%	272,942	70	4,839	69	14.70	0.0254	6,940	7,009	3,823	0.4110	112,189	116,012
1961	430,457.01	-125%	538,071	70	9,539	136	15.34	0.0245	13,186	13,322	7,449	0.3955	212,817	220,266
1962	468,903.19	-125%	586,129	70	10,391	148	16.00	0.0236	13,828	13,976	8,016	0.3801	222,788	230,804
1963	461,218.63	-125%	576,523	70	10,221	146	16.67	0.0227	13,086	13,232	7,787	0.3650	210,453	218,240
1964	440,950.39	-125%	551,188	70	9,772	140	17.35	0.0218	12,030	12,170	7,350	0.3503	193,100	200,449
1965	452,682.16	-125%	565,853	70	10,032	143	18.04	0.0210	11,869	12,012	7,446	0.3360	190,121	197,567
1966	498,400.68	-125%	623,001	70	11,045	158	18.74	0.0201	12,551	12,709	8,088	0.3220	200,612	208,700
1967	562,172.65	-125%	702,716	70	12,458	178	19.46	0.0193	13,582	13,760	8,995	0.3082	216,581	225,576
1968	765,618.70	-125%	957,023	70	16,967	242	20.18	0.0185	17,746	17,988	12,075	0.2950	282,287	294,363
1969	647,884.90	-125%	809,856	70	14,358	205	20.91	0.0178	14,398	14,604	10,069	0.2821	228,449	238,518
1970	755,795.59	-125%	944,744	70	16,749	239	21.65	0.0170	16,096	16,335	11,569	0.2696	254,678	266,247
1971	919,843.84	-125%	1,149,805	70	20,384	291	22.40	0.0163	18,761	19,052	13,861	0.2574	295,988	309,850
1972	826,364.23	-125%	1,032,955	70	18,313	262	23.17	0.0156	16,123	16,385	12,251	0.2455	253,576	265,828
1973	627,465.80	-125%	784,332	70	13,905	199	23.94	0.0149	11,711	11,910	9,150	0.2341	183,585	192,735
1974	1,014,342.56	-125%	1,267,928	70	22,478	321	24.73	0.0143	18,090	18,411	14,537	0.2229	282,575	297,112
1975	618,656.81	-125%	773,321	70	13,710	196	25.52	0.0136	10,542	10,738	8,712	0.2122	164,067	172,779
1976	776,671.06	-125%	970,839	70	17,212	246	26.33	0.0130	12,631	12,877	10,738	0.2017	195,797	206,535
1977	873,414.74	-125%	1,091,768	70	19,355	277	27.15	0.0124	13,549	13,826	11,848	0.1916	209,134	220,982
1978	816,798.28	-125%	1,020,998	70	18,101	259	27.97	0.0118	12,086	12,345	10,868	0.1819	185,718	196,586
1979	859,210.57	-125%	1,074,013	70	19,041	272	28.81	0.0113	12,113	12,385	11,204	0.1725	185,233	196,437
1980	1,251,725.95	-125%	1,564,657	70	27,739	396	29.66	0.0107	16,804	17,200	15,986	0.1634	255,633	271,618
1981	1,426,651.93	-125%	1,783,315	70	31,615	452	30.52	0.0102	18,227	18,678	17,831	0.1546	275,746	293,577
1982	1,437,996.85	-125%	1,797,496	70	31,867	455	31.38	0.0097	17,483	17,939	17,581	0.1463	262,964	280,545
1983	1,174,422.94	-125%	1,468,029	70	26,026	372	32.26	0.0092	13,573	13,945	14,032	0.1382	202,862	216,893
1984	1,402,996.81	-125%	1,753,746	70	31,091	444	33.14	0.0088	15,413	15,857	16,372	0.1305	228,828	245,199
1985	1,660,324.45	-125%	2,075,406	70	36,794	526	34.03	0.0083	17,329	17,854	18,907	0.1231	255,424	274,331
1986	1,162,359.71	-125%	1,452,950	70	25,759	368	34.93	0.0079	11,518	11,886	12,905	0.1160	168,481	181,386
1987	1,094,541.81	-125%	1,368,177	70	24,256	347	35.84	0.0075	10,292	10,639	11,837	0.1091	149,309	161,146
1988	1,082,111.35	-125%	1,352,639	70	23,980	343	36.76	0.0071	9,650	9,993	11,387	0.1026	138,756	150,143
1989	1,192,811.96	-125%	1,491,015	70	26,433	378	37.68	0.0068	10,088	10,466	12,205	0.0964	143,691	155,896
1990	1,882,932.42	-125%	2,353,666	70	41,727	596	38.61	0.0064	15,094	15,691	18,712	0.0904	212,817	231,528
1991	1,915,315.32	-125%	2,394,144	70	42,445	606	39.54	0.0061	14,553	15,159	18,469	0.0848	202,970	221,439
1992	1,809,617.45	-125%	2,262,022	70	40,102	573	40.48	0.0058	13,025	13,598	16,912	0.0794	179,547	196,458
1993	1,923,128.52	-125%	2,403,911	70	42,618	609	41.43	0.0055	13,105	13,714	17,394	0.0742	178,377	195,771
1994	2,988,080.66	-125%	3,735,101	70	66,218	946	42.38	0.0052	19,278	20,224	26,128	0.0693	258,868	284,996
1995	2,210,611.02	-125%	2,763,264	70	48,989	700	43.33	0.0049	13,502	14,202	18,665	0.0647	178,705	197,369
1996	2,173,675.95	-125%	2,717,095	70	48,170	688	44.29	0.0046	12,562	13,250	17,692	0.0602	163,673	181,365
1997	2,472,530.23	-125%	3,090,663	70	54,793	783	45.26	0.0044	13,513	14,296	19,365	0.0560	173,080	192,446
1998	4,720,518.43	-125%	5,900,648	70	104,610	1,494	46.23	0.0041	24,396	25,891	35,522	0.0520	306,798	342,321
1999	1,370,911.74	-125%	1,713,640	70	30,380	434	47.20	0.0039	6,700	7,134	9,895	0.0482	82,606	92,501
2000	892,373.59	-125%	1,115,467	70	19,776	283	48.17	0.0037	4,124	4,407	6,167	0.0446	49,774	55,941
2001	3,611,680.68	-125%	4,514,601	70	80,037	1,143	49.15	0.0035	15,776	16,919	23,840	0.0412	185,997	209,836
2002	94,743.94	-125%	118,430	70	2,100	30	50.13	0.0033	391	421	596	0.0380	4,496	5,092
2003	640,277.74	-125%	800,347	70	14,189	203	51.11	0.0031	2,498	2,701	3,829	0.0349	27,938	31,767
2004	1,103,082.66	-125%	1,378,853	70	24,445	349	52.09	0.0029	4,068	4,417	6,254	0.0320	44,148	50,402
2005	2,646,366.81	-125%	3,307,959	70	58,645	838	53.08	0.0028	9,217	10,055	14,175	0.0293	96,791	110,967
2006	679,984.58	-125%	849,981	70	15,069	215	54.07	0.0026	2,237	2,452	3,429	0.0267	22,656	26,086
2007	2,939,932.49	-125%	3,674,916	70	65,151	931	55.06	0.0025	9,136	10,067	13,905	0.0242	88,914	102,819
2008	7,083,953.91	-125%	8,854,942	70	156,985	2,243	56.05	0.0023	20,793	23,036	31,285	0.0219	193,664	224,949
2009	1,131,529.96	-125%	1,414,412	70	25,075	358	57.04	0.0022	3,137	3,495	4,643	0.0197	27,829	32,472
2010	5,354,577.72	-125%	6,693,222	70	118,661	1,695	58.03	0.0021	14,023	15,718	20,291	0.0176	117,814	138,105
2011	3,613,055.10	-125%	4,516,319	70	80,068	1,144	59.03	0.0020	8,932	10,076	12,548	0.0156	70,564	83,111
2012	6,541,671.66	-125%	8,177,090	70	144,968	2,071	60.02	0.0019	15,276	17,347	20,668	0.0138	112,641	133,309
2013	2,347,409.29	-125%	2,934,262	70	52,020	743	61.02	0.0018	5,175	5,918	6,673	0.0120	35,245	41,919
2014	4,303,700.82	-125%	5,379,626	70	95,373	1,362	62.01	0.0017	8,961	10,324	10,886	0.0104	55,749	66,635
2015	2,997,318.75	-125%	3,746,648	70	66,422	949	63.01	0.0016	5,892	6,841	6,633	0.0088	32,934	39,567
2016	4,103,649.97	-125%	5,129,562	70	90,939	1,299	64.01	0.0015	7,615	8,914	7,782	0.0073	37,476	45,257
2017	3,680,927.97	-125%	4,601,160	70	81,572	1,165	65.01	0.0014	6,448	7,614	5,815	0.0059	27,167	32,982
2018	5,383,870.25	-125%	6,729,838	70	119,310	1,704	66.00	0.0013	8,909	10,613	6,818	0.0046	30,919	37,736
2019	4,209,358.42	-125%	5,261,698	70	93,282	1,333	67.00	0.0012	6,575	7,908	3,998	0.0033	17,598	21,596
2020	6,082,965.92	-125%	7,603,707	70	134,802	1,926	68.00	0.0012	8,970	10,896	3,851	0.0022	16,462	20,313
2021	7,024,249.33	-125%	8,780,312	70	155,662	2,224	69.00	0.0011	9,778	12,002	2,224	0.0011	9,231	11,454
2022	3,167,199.58	-125%	3,958,999	70	70,187	1,003	69.75	0.0011	4,222	5,225	251	0.0003	1,018	1,269
	131,651,738.90		164,564,673.63			41,678.35			840,279.40	881,957.75			11,252,488.49	12,061,383.74

Account 365.00 Overhead Conductors and Devices
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1945	644,479.04	-100%	644,479	62	18,115	292	16.07	0.0235	15,143	15,435	13,420	0.3681	237,246	250,665
1953	895,398.75	-100%	895,399	62	25,168	406	19.50	0.0193	17,266	17,672	17,252	0.2971	266,002	283,254
1954	111,190.94	-100%	111,191	62	3,125	50	19.95	0.0188	2,089	2,140	2,120	0.2888	32,107	34,227
1955	152,221.62	-100%	152,222	62	4,279	69	20.41	0.0183	2,785	2,854	2,870	0.2805	42,693	45,564
1956	123,645.44	-100%	123,645	62	3,475	56	20.87	0.0178	2,203	2,259	2,306	0.2724	33,681	35,986
1957	112,393.94	-100%	112,394	62	3,159	51	21.34	0.0173	1,949	2,000	2,072	0.2644	29,714	31,786
1958	209,224.37	-100%	209,224	62	5,881	95	21.81	0.0169	3,532	3,627	3,812	0.2566	53,678	57,490
1959	310,197.01	-100%	310,197	62	8,719	141	22.29	0.0164	5,094	5,234	5,584	0.2488	77,175	82,760
1960	180,585.58	-100%	180,586	62	5,076	82	22.77	0.0160	2,884	2,966	3,212	0.2412	43,565	46,777
1961	400,364.55	-100%	400,365	62	11,253	182	23.26	0.0155	6,217	6,398	7,031	0.2337	93,584	100,615
1962	431,487.68	-100%	431,488	62	12,128	196	23.75	0.0151	6,514	6,709	7,482	0.2265	97,714	105,196
1963	369,959.70	-100%	369,960	62	10,399	168	24.25	0.0147	5,426	5,594	6,331	0.2192	81,106	87,438
1964	369,804.46	-100%	369,804	62	10,394	168	24.76	0.0142	5,267	5,435	6,243	0.2121	78,424	84,667
1965	402,574.73	-100%	402,575	62	11,315	183	25.27	0.0138	5,568	5,750	6,703	0.2051	82,574	89,278
1966	462,636.30	-100%	462,636	62	13,004	210	25.79	0.0134	6,209	6,419	7,595	0.1982	91,709	99,304
1967	524,877.14	-100%	524,877	62	14,753	238	26.31	0.0130	6,837	7,075	8,493	0.1916	100,541	109,034
1968	862,985.97	-100%	862,986	62	24,256	391	26.84	0.0126	10,903	11,294	13,756	0.1849	159,607	173,362
1969	596,143.19	-100%	596,143	62	16,756	270	27.37	0.0123	7,305	7,576	9,359	0.1785	106,436	115,795
1970	656,803.99	-100%	656,804	62	18,461	298	27.91	0.0119	7,802	8,100	10,151	0.1722	113,109	123,259
1971	425,447.84	-100%	425,448	62	11,958	193	28.45	0.0115	4,899	5,092	6,471	0.1661	70,656	77,127
1972	652,132.00	-100%	652,132	62	18,330	296	29.00	0.0112	7,275	7,571	9,756	0.1600	104,353	114,110
1973	355,831.35	-100%	355,831	62	10,002	161	29.56	0.0108	3,844	4,005	5,233	0.1540	54,815	60,048
1974	542,330.32	-100%	542,330	62	15,244	246	30.12	0.0105	5,672	5,918	7,838	0.1483	80,408	88,246
1975	1,777.61	-100%	1,778	62	50	1	30.69	0.0101	18	19	25	0.1426	253	279
1976	989,433.43	-100%	989,433	62	27,811	449	31.26	0.0098	9,691	10,139	13,789	0.1371	135,605	149,394
1977	940,522.51	-100%	940,523	62	26,436	426	31.84	0.0095	8,909	9,335	12,860	0.1316	123,797	136,657
1978	735,727.15	-100%	735,727	62	20,680	334	32.42	0.0092	6,740	7,073	9,866	0.1264	92,979	102,845
1979	778,635.94	-100%	778,636	62	21,886	353	33.01	0.0089	6,895	7,248	10,233	0.1212	94,382	104,615
1980	1,272,085.73	-100%	1,272,086	62	35,755	577	33.61	0.0086	10,881	11,458	16,372	0.1161	147,742	164,114
1981	1,299,608.75	-100%	1,299,609	62	36,529	589	34.20	0.0083	10,745	11,334	16,379	0.1113	144,673	161,053
1982	1,227,085.50	-100%	1,227,086	62	34,490	556	34.81	0.0080	9,795	10,352	15,126	0.1065	130,692	145,818
1983	735,887.76	-100%	735,888	62	20,684	334	35.42	0.0077	5,671	6,005	8,867	0.1019	74,956	83,823
1984	595,161.43	-100%	595,161	62	16,729	270	36.03	0.0074	4,428	4,698	7,007	0.0974	57,951	64,958
1985	1,178,245.00	-100%	1,178,245	62	33,118	534	36.65	0.0072	8,460	8,994	13,541	0.0930	109,538	123,079
1986	866,553.19	-100%	866,553	62	24,357	393	37.28	0.0069	6,000	6,393	9,711	0.0887	76,822	86,533
1987	612,538.73	-100%	612,539	62	17,217	278	37.91	0.0067	4,090	4,368	6,690	0.0845	51,754	58,443
1988	602,186.81	-100%	602,187	62	16,926	273	38.54	0.0064	3,878	4,151	6,405	0.0805	48,462	54,867
1989	690,700.86	-100%	690,701	62	19,414	313	39.18	0.0062	4,286	4,600	7,146	0.0765	52,871	60,016
1990	1,369,164.76	-100%	1,369,165	62	38,484	621	39.82	0.0060	8,189	8,810	13,767	0.0728	99,618	113,385
1991	1,185,870.74	-100%	1,185,871	62	33,332	538	40.47	0.0058	6,832	7,370	11,575	0.0691	81,886	93,461
1992	2,073,849.04	-100%	2,073,849	62	58,291	940	41.12	0.0055	11,509	12,450	19,631	0.0655	135,796	155,427
1993	2,071,334.86	-100%	2,071,335	62	58,220	939	41.77	0.0053	11,073	12,012	18,997	0.0620	128,507	147,504
1994	3,377,400.65	-100%	3,377,401	62	94,931	1,531	42.43	0.0051	17,381	18,912	29,964	0.0587	198,177	228,142
1995	2,545,801.14	-100%	2,545,801	62	71,556	1,154	43.09	0.0050	12,613	13,767	21,825	0.0554	141,138	162,963
1996	1,876,746.05	-100%	1,876,746	62	52,751	851	43.75	0.0048	8,951	9,802	15,527	0.0523	98,197	113,724
1997	3,065,237.60	-100%	3,065,238	62	86,156	1,390	44.42	0.0046	14,066	15,456	24,430	0.0493	151,047	175,477
1998	5,931,495.97	-100%	5,931,496	62	166,720	2,689	45.09	0.0044	26,189	28,878	45,472	0.0463	274,910	320,382
1999	846,969.46	-100%	846,969	62	23,806	384	45.76	0.0042	3,598	3,982	6,236	0.0435	36,867	43,103
2000	1,076,056.29	-100%	1,076,056	62	30,245	488	46.44	0.0041	4,396	4,883	7,591	0.0408	43,878	51,468
2001	3,109,471.60	-100%	3,109,472	62	87,400	1,410	47.12	0.0039	12,214	13,623	20,976	0.0381	118,565	139,541
2002	201,570.18	-100%	201,570	62	5,666	91	47.80	0.0038	761	853	1,298	0.0356	7,173	8,471
2003	677,300.12	-100%	677,300	62	19,037	307	48.48	0.0036	2,460	2,767	4,151	0.0331	22,445	26,596
2004	1,136,683.78	-100%	1,136,684	62	31,949	515	49.17	0.0035	3,967	4,483	6,611	0.0308	34,955	41,567
2005	3,303,623.82	-100%	3,303,624	62	92,857	1,498	49.85	0.0034	11,088	12,586	18,197	0.0285	94,123	112,320
2006	1,112,958.05	-100%	1,112,958	62	31,283	505	50.54	0.0032	3,590	4,094	5,782	0.0263	29,254	35,037
2007	2,263,823.54	-100%	2,263,824	62	63,631	1,026	51.24	0.0031	7,013	8,040	11,043	0.0241	54,638	65,681
2008	4,467,470.82	-100%	4,467,471	62	125,570	2,025	51.93	0.0030	13,301	15,326	20,395	0.0221	98,729	119,124
2009	1,241,586.69	-100%	1,241,587	62	34,898	563	52.63	0.0029	3,550	4,113	5,274	0.0201	24,975	30,249
2010	3,783,934.89	-100%	3,783,935	62	106,357	1,715	53.33	0.0027	10,393	12,108	14,873	0.0182	68,902	83,775
2011	4,624,473.45	-100%	4,624,473	62	129,983	2,096	54.04	0.0026	12,192	14,289	16,688	0.0164	75,624	92,312
2012	13,497,172.13	-100%	13,497,172	62	379,373	6,119	54.74	0.0025	34,179	40,298	44,423	0.0146	197,001	241,424
2013	3,060,191.13	-100%	3,060,191	62	86,015	1,387	55.45	0.0024	7,439	8,826	9,087	0.0129	39,428	48,515
2014	6,833,681.97	-100%	6,833,682	62	192,078	3,098	56.17	0.0023	15,937	19,035	18,062	0.0112	76,666	94,727
2015	3,911,265.73	-100%	3,911,266	62	109,936	1,773	56.88	0.0022	8,756	10,529	9,079	0.0096	37,715	46,794
2016	6,478,185.01	-100%	6,478,185	62	182,086	2,937	57.60	0.0021	13,913	16,850	12,922	0.0081	52,531	65,454
2017	5,598,530.18	-100%	5,598,530	62	157,361	2,538	58.33	0.0021	11,528	14,067	9,315	0.0066	37,048	46,363
2018	9,064,774.07	-100%	9,064,774	62	254,789	4,110	59.06	0.0020	17,897	22,007	12,082	0.0052	47,023	59,105
2019	9,602,616.32	-100%	9,602,616	62	269,906	4,353	59.79	0.0019	18,179	22,532	9,621	0.0038	36,646	46,267
2020	10,084,138.09	-100%	10,084,138	62	283,441	4,572	60.52	0.0018	18,304	22,876	6,766	0.0025	25,226	31,992
2021	7,177,268.13	-100%	7,177,268	62	201,736	3,254	61.26	0.0017	12,484	15,738	2,408	0.0012	8,786	11,194
2022	2,526,404.97	-100%	2,526,405	62	71,011	1,145	61.81	0.0017	4,257	5,403	218	0.0003	782	999
	151,495,917.54		151,495,917.54		4,258,186.20	68,680.42			611,372.28	680,052.71	793,390.45		6,051,633.08	6,845,023.54

Account 365.10 Overhead Conductors and Devices - Clearing
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1945	198,445.64	0%	0	70	0	0	7.48	0.0385	0	0	-	0.6322	-	-
1953	257,267.91	0%	0	70	0	0	10.72	0.0320	0	0	-	0.5215	-	-
1954	26,518.65	0%	0	70	0	0	11.22	0.0311	0	0	-	0.5062	-	-
1955	49,708.01	0%	0	70	0	0	11.75	0.0301	0	0	-	0.4905	-	-
1956	17,511.50	0%	0	70	0	0	12.29	0.0292	0	0	-	0.4749	-	-
1957	31,497.90	0%	0	70	0	0	12.86	0.0283	0	0	-	0.4590	-	-
1958	63,506.77	0%	0	70	0	0	13.45	0.0273	0	0	-	0.4431	-	-
1959	68,670.28	0%	0	70	0	0	14.06	0.0264	0	0	-	0.4271	-	-
1960	35,567.72	0%	0	70	0	0	14.70	0.0254	0	0	-	0.4110	-	-
1961	62,506.71	0%	0	70	0	0	15.34	0.0245	0	0	-	0.3955	-	-
1962	66,463.18	0%	0	70	0	0	16.00	0.0236	0	0	-	0.3801	-	-
1963	63,613.40	0%	0	70	0	0	16.67	0.0227	0	0	-	0.3650	-	-
1964	51,627.12	0%	0	70	0	0	17.35	0.0218	0	0	-	0.3503	-	-
1965	58,305.14	0%	0	70	0	0	18.04	0.0210	0	0	-	0.3360	-	-
1966	79,089.94	0%	0	70	0	0	18.74	0.0201	0	0	-	0.3220	-	-
1967	72,188.05	0%	0	70	0	0	19.46	0.0193	0	0	-	0.3082	-	-
1968	118,936.55	0%	0	70	0	0	20.18	0.0185	0	0	-	0.2950	-	-
1969	104,544.79	0%	0	70	0	0	20.91	0.0178	0	0	-	0.2821	-	-
1970	56,851.56	0%	0	70	0	0	21.65	0.0170	0	0	-	0.2696	-	-
1971	160,188.37	0%	0	70	0	0	22.40	0.0163	0	0	-	0.2574	-	-
1972	135,363.03	0%	0	70	0	0	23.17	0.0156	0	0	-	0.2455	-	-
1973	49,931.61	0%	0	70	0	0	23.94	0.0149	0	0	-	0.2341	-	-
1974	61,543.99	0%	0	70	0	0	24.73	0.0143	0	0	-	0.2229	-	-
1975	36,942.81	0%	0	70	0	0	25.52	0.0136	0	0	-	0.2122	-	-
1976	26,122.80	0%	0	70	0	0	26.33	0.0130	0	0	-	0.2017	-	-
1977	16,917.10	0%	0	70	0	0	27.15	0.0124	0	0	-	0.1916	-	-
1978	44,528.17	0%	0	70	0	0	27.97	0.0118	0	0	-	0.1819	-	-
1979	33,294.54	0%	0	70	0	0	28.81	0.0113	0	0	-	0.1725	-	-
1980	26,021.09	0%	0	70	0	0	29.66	0.0107	0	0	-	0.1634	-	-
1981	17,176.51	0%	0	70	0	0	30.52	0.0102	0	0	-	0.1546	-	-
1982	91,864.42	0%	0	70	0	0	31.38	0.0097	0	0	-	0.1463	-	-
1983	47,413.39	0%	0	70	0	0	32.26	0.0092	0	0	-	0.1382	-	-
1984	58,369.07	0%	0	70	0	0	33.14	0.0088	0	0	-	0.1305	-	-
1985	99,949.36	0%	0	70	0	0	34.03	0.0083	0	0	-	0.1231	-	-
1986	51,623.71	0%	0	70	0	0	34.93	0.0079	0	0	-	0.1160	-	-
1987	56,351.74	0%	0	70	0	0	35.84	0.0075	0	0	-	0.1091	-	-
1988	76,307.29	0%	0	70	0	0	36.76	0.0071	0	0	-	0.1026	-	-
1989	57,472.69	0%	0	70	0	0	37.68	0.0068	0	0	-	0.0964	-	-
1990	145,517.80	0%	0	70	0	0	38.61	0.0064	0	0	-	0.0904	-	-
1991	222,430.29	0%	0	70	0	0	39.54	0.0061	0	0	-	0.0848	-	-
1992	169,561.57	0%	0	70	0	0	40.48	0.0058	0	0	-	0.0794	-	-
1993	293,634.53	0%	0	70	0	0	41.43	0.0055	0	0	-	0.0742	-	-
1994	247,471.71	0%	0	70	0	0	42.38	0.0052	0	0	-	0.0693	-	-
1995	336,884.25	0%	0	70	0	0	43.33	0.0049	0	0	-	0.0647	-	-
1996	211,127.65	0%	0	70	0	0	44.29	0.0046	0	0	-	0.0602	-	-
1997	77,354.70	0%	0	70	0	0	45.26	0.0044	0	0	-	0.0560	-	-
1998	511,739.12	0%	0	70	0	0	46.23	0.0041	0	0	-	0.0520	-	-
1999	64,632.73	0%	0	70	0	0	47.20	0.0039	0	0	-	0.0482	-	-
2000	26,542.18	0%	0	70	0	0	48.17	0.0037	0	0	-	0.0446	-	-
2001	269,299.37	0%	0	70	0	0	49.15	0.0035	0	0	-	0.0412	-	-
2002	6,176.60	0%	0	70	0	0	50.13	0.0033	0	0	-	0.0380	-	-
2003	13,037.11	0%	0	70	0	0	51.11	0.0031	0	0	-	0.0349	-	-
2004	115,193.78	0%	0	70	0	0	52.09	0.0029	0	0	-	0.0320	-	-
2005	964,066.98	0%	0	70	0	0	53.08	0.0028	0	0	-	0.0293	-	-
2006	54,368.26	0%	0	70	0	0	54.07	0.0026	0	0	-	0.0267	-	-
2009	5,607.89	0%	0	70	0	0	57.04	0.0022	0	0	-	0.0197	-	-
2011	3,583,609.65	0%	0	70	0	0	59.03	0.0020	0	0	-	0.0156	-	-
2012	2,000.53	0%	0	70	0	0	60.02	0.0019	0	0	-	0.0138	-	-
2013	23,172,747.85	0%	0	70	0	0	61.02	0.0018	0	0	-	0.0120	-	-
2014	2,724,673.77	0%	0	70	0	0	62.01	0.0017	0	0	-	0.0104	-	-
2015	9,549,735.28	0%	0	70	0	0	63.01	0.0016	0	0	-	0.0088	-	-
2016	9,628,276.49	0%	0	70	0	0	64.01	0.0015	0	0	-	0.0073	-	-
2017	2,403,223.79	0%	0	70	0	0	65.01	0.0014	0	0	-	0.0059	-	-
2018	8,220,756.12	0%	0	70	0	0	66.00	0.0013	0	0	-	0.0046	-	-
2019	4,013,147.47	0%	0	70	0	0	67.00	0.0012	0	0	-	0.0033	-	-
2020	3,903,913.96	0%	0	70	0	0	68.00	0.0012	0	0	-	0.0022	-	-
2021	4,108,534.21	0%	0	70	0	0	69.00	0.0011	0	0	-	0.0011	-	-
2022	38,208.87	0%	0	70	0	0	69.75	0.0011	0	0	-	0.0003	-	-
	77,713,677.02		-		-	-			-	-	-		-	#REF!

Account 366.00 Underground Conduit
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1964	1,065.97	-50%	533	65	13	0	13.37	0.0275	15	15	10	0.4393	234	244
1965	3,441.97	-50%	1,721	65	41	1	14.01	0.0265	46	46	32	0.4225	727	759
1966	42,985.37	-50%	21,493	65	508	8	14.67	0.0255	547	555	394	0.4059	8,723	9,117
1967	24,198.31	-50%	12,099	65	286	4	15.34	0.0245	296	301	219	0.3896	4,714	4,932
1968	24,786.03	-50%	12,393	65	293	5	16.02	0.0236	292	297	221	0.3737	4,632	4,852
1969	39,680.53	-50%	19,840	65	469	7	16.71	0.0226	449	457	349	0.3582	7,108	7,456
1970	25,335.98	-50%	12,668	65	300	5	17.41	0.0218	276	280	219	0.3431	4,347	4,566
1971	30,636.17	-50%	15,318	65	362	6	18.12	0.0209	320	325	261	0.3284	5,031	5,292
1972	106,360.09	-50%	53,180	65	1,258	19	18.84	0.0200	1,065	1,085	893	0.3141	16,706	17,599
1973	319,345.25	-50%	159,673	65	3,776	58	19.57	0.0192	3,067	3,125	2,639	0.3002	47,938	50,577
1974	329,428.91	-50%	164,714	65	3,895	60	20.32	0.0184	3,030	3,090	2,677	0.2865	47,196	49,874
1975	249,671.72	-50%	124,836	65	2,952	45	21.07	0.0176	2,199	2,245	1,995	0.2734	34,132	36,127
1976	479,289.48	-50%	239,645	65	5,667	87	21.84	0.0169	4,038	4,126	3,763	0.2605	62,434	66,197
1977	404,216.25	-50%	202,108	65	4,779	74	22.62	0.0161	3,256	3,330	3,116	0.2480	50,131	53,247
1978	536,944.55	-50%	268,472	65	6,348	98	23.41	0.0154	4,133	4,231	4,062	0.2360	63,347	67,409
1979	538,814.09	-50%	269,407	65	6,371	98	24.22	0.0147	3,958	4,056	3,997	0.2241	60,379	64,376
1980	586,246.21	-50%	293,123	65	6,931	107	25.03	0.0140	4,110	4,217	4,262	0.2128	62,383	66,646
1981	370,766.47	-50%	185,383	65	4,384	67	25.86	0.0134	2,478	2,546	2,640	0.2018	37,407	40,047
1982	348,166.71	-50%	174,083	65	4,116	63	26.69	0.0127	2,218	2,282	2,426	0.1913	33,295	35,721
1983	446,912.40	-50%	223,456	65	5,284	81	27.54	0.0121	2,712	2,793	3,045	0.1810	40,443	43,488
1984	376,162.61	-50%	188,081	65	4,447	68	28.40	0.0115	2,172	2,240	2,504	0.1711	32,180	34,684
1985	821,197.23	-50%	410,599	65	9,709	149	29.26	0.0110	4,512	4,662	5,339	0.1617	66,387	71,725
1986	883,472.99	-50%	441,736	65	10,446	161	30.14	0.0104	4,615	4,775	5,602	0.1525	67,375	72,977
1987	803,670.10	-50%	401,835	65	9,502	146	31.03	0.0099	3,988	4,134	4,966	0.1437	57,751	62,716
1988	1,027,170.99	-50%	513,585	65	12,144	187	31.92	0.0094	4,842	5,029	6,181	0.1354	69,515	75,696
1989	1,104,286.16	-50%	552,143	65	13,056	201	32.83	0.0089	4,940	5,141	6,462	0.1272	70,250	76,712
1990	1,305,531.46	-50%	652,766	65	15,436	237	33.74	0.0085	5,542	5,780	7,423	0.1195	78,023	85,446
1991	1,127,295.33	-50%	563,648	65	13,328	205	34.66	0.0081	4,538	4,743	6,221	0.1121	63,205	69,426
1992	1,335,101.81	-50%	667,551	65	15,785	243	35.58	0.0076	5,098	5,340	7,145	0.1051	70,177	77,322
1993	1,500,777.35	-50%	750,389	65	17,744	273	36.52	0.0072	5,428	5,701	7,775	0.0983	73,792	81,567
1994	1,837,020.52	-50%	918,510	65	21,720	334	37.46	0.0069	6,294	6,628	9,202	0.0919	84,419	93,621
1995	2,547,665.21	-50%	1,273,833	65	30,122	463	38.40	0.0065	8,269	8,732	12,327	0.0858	109,317	121,644
1996	1,723,797.10	-50%	861,899	65	20,381	314	39.35	0.0061	5,297	5,610	8,043	0.0800	68,941	76,984
1997	3,498,702.66	-50%	1,749,351	65	41,366	636	40.31	0.0058	10,172	10,809	15,713	0.0744	130,173	145,885
1998	5,071,671.78	-50%	2,535,836	65	59,964	923	41.27	0.0055	13,952	14,875	21,891	0.0691	175,318	197,209
1999	230,354.02	-50%	115,177	65	2,724	42	42.23	0.0052	600	642	954	0.0641	7,388	8,342
2000	2,242,005.30	-50%	1,121,003	65	26,508	408	43.20	0.0049	5,519	5,927	8,890	0.0594	66,557	75,448
2001	5,911,100.92	-50%	2,955,550	65	69,888	1,075	44.17	0.0047	13,760	14,835	22,397	0.0549	162,145	184,541
2002	338,059.67	-50%	169,030	65	3,997	61	45.15	0.0044	744	805	1,221	0.0506	8,545	9,765
2003	264,990.08	-50%	132,495	65	3,133	48	46.13	0.0042	551	599	910	0.0465	6,158	7,068
2004	2,246,607.61	-50%	1,123,304	65	26,562	409	47.11	0.0039	4,415	4,823	7,311	0.0426	47,886	55,197
2005	2,616,416.24	-50%	1,308,208	65	30,935	476	48.09	0.0037	4,859	5,335	8,048	0.0390	51,009	59,057
2006	770,525.36	-50%	385,263	65	9,110	140	49.08	0.0035	1,352	1,492	2,231	0.0355	13,684	15,915
2007	2,257,391.75	-50%	1,128,696	65	26,690	411	50.06	0.0033	3,743	4,153	6,135	0.0323	36,425	42,559
2008	2,187,063.81	-50%	1,093,532	65	25,858	398	51.05	0.0031	3,425	3,823	5,550	0.0292	31,900	37,449
2009	382,527.20	-50%	191,264	65	4,523	70	52.04	0.0030	566	635	902	0.0262	5,019	5,921
2010	1,022,572.17	-50%	511,286	65	12,090	186	53.04	0.0028	1,428	1,614	2,225	0.0235	11,990	14,215
2011	1,437,126.81	-50%	718,563	65	16,992	261	54.03	0.0026	1,896	2,157	2,868	0.0208	14,975	17,842
2012	939,020.96	-50%	469,510	65	11,102	171	55.02	0.0025	1,170	1,341	1,705	0.0184	8,627	10,331
2013	1,267,034.71	-50%	633,517	65	14,980	230	56.02	0.0024	1,490	1,721	2,070	0.0160	10,150	12,219
2014	759,422.93	-50%	379,711	65	8,979	138	57.02	0.0022	843	981	1,102	0.0138	5,240	6,343
2015	961,871.62	-50%	480,936	65	11,372	175	58.01	0.0021	1,009	1,184	1,223	0.0117	5,639	6,862
2016	1,203,095.28	-50%	601,548	65	14,224	219	59.01	0.0020	1,191	1,410	1,311	0.0097	5,862	7,173
2017	1,060,830.00	-50%	530,415	65	12,542	193	60.01	0.0019	991	1,184	963	0.0079	4,177	5,140
2018	1,233,635.40	-50%	616,818	65	14,586	224	61.00	0.0018	1,089	1,313	898	0.0061	3,780	4,677
2019	2,642,034.18	-50%	1,321,017	65	31,237	481	62.00	0.0017	2,202	2,682	1,442	0.0045	5,893	7,335
2020	2,012,718.13	-50%	1,006,359	65	23,797	366	63.00	0.0016	1,583	1,950	732	0.0029	2,906	3,638
2021	2,183,234.73	-50%	1,091,617	65	25,813	397	64.00	0.0015	1,621	2,019	397	0.0014	1,531	1,928
2022	713,219.22	-50%	356,610	65	8,433	130	64.75	0.0014	507	637	32	0.0003	122	155
	66,754,673.86		33,377,336.93		789,257.08	12,142.42			184,719.19	196,861.61	245,525.14		2,325,737.76	2,571,262.90

Account 367.00 Underground Conductors and Devices
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1966	9,176.93	-50%	4,588	44	364	8	4.61	0.0455	209	217	326	0.6875	3,155	3,480
1967	7,336.06	-50%	3,668	44	291	7	4.88	0.0448	164	171	259	0.6757	2,478	2,737
1968	31,633.89	-50%	15,817	44	1,254	28	5.17	0.0440	696	725	1,107	0.6631	10,489	11,596
1969	48,368.58	-50%	24,184	44	1,917	44	5.46	0.0433	1,047	1,091	1,679	0.6508	15,740	17,420
1970	75,607.49	-50%	37,804	44	2,997	68	5.77	0.0425	1,608	1,676	2,604	0.6379	24,116	26,720
1971	95,505.53	-50%	47,753	44	3,786	86	6.10	0.0417	1,993	2,079	3,261	0.6244	29,818	33,079
1972	71,140.41	-50%	35,570	44	2,820	64	6.44	0.0409	1,456	1,520	2,407	0.6108	21,725	24,132
1973	64,600.01	-50%	32,300	44	2,561	58	6.79	0.0401	1,295	1,354	2,166	0.5970	19,283	21,448
1974	466,780.44	-50%	233,390	44	18,503	421	7.17	0.0392	9,157	9,577	15,488	0.5823	135,914	151,402
1975	518,107.46	-50%	259,054	44	20,538	467	7.56	0.0384	9,938	10,405	17,009	0.5676	147,051	164,061
1976	545,677.88	-50%	272,839	44	21,631	492	7.98	0.0374	10,217	10,708	17,708	0.5522	150,657	168,365
1977	799,577.34	-50%	399,789	44	31,695	720	8.42	0.0365	14,596	15,316	25,630	0.5364	214,438	240,068
1978	909,243.36	-50%	454,622	44	36,043	819	8.88	0.0356	16,164	16,983	28,768	0.5203	236,530	265,298
1979	929,138.65	-50%	464,569	44	36,831	837	9.36	0.0346	16,067	16,904	28,996	0.5039	234,109	263,105
1980	898,439.97	-50%	449,220	44	35,614	809	9.86	0.0336	15,095	15,904	27,633	0.4874	218,935	246,569
1981	973,038.38	-50%	486,519	44	38,571	877	10.38	0.0326	15,866	16,742	29,472	0.4706	228,977	258,449
1982	803,004.97	-50%	401,502	44	31,831	723	10.93	0.0316	12,685	13,408	23,924	0.4535	182,079	206,003
1983	1,063,162.86	-50%	531,581	44	42,144	958	11.49	0.0306	16,261	17,219	31,139	0.4366	232,078	263,216
1984	922,308.95	-50%	461,154	44	36,560	831	12.08	0.0296	13,636	14,466	26,523	0.4193	193,381	219,904
1985	1,529,705.48	-50%	764,853	44	60,638	1,378	12.69	0.0285	21,834	23,213	43,149	0.4021	307,565	350,714
1986	1,699,896.09	-50%	849,948	44	67,384	1,531	13.31	0.0275	23,412	24,944	47,000	0.3852	327,427	374,428
1987	1,187,678.48	-50%	593,839	44	47,080	1,070	13.95	0.0265	15,766	16,836	32,153	0.3684	218,781	250,934
1988	3,351,058.70	-50%	1,675,529	44	132,836	3,019	14.61	0.0256	42,823	45,842	88,729	0.3517	589,309	678,038
1989	3,210,119.56	-50%	1,605,060	44	127,250	2,892	15.29	0.0246	39,446	42,338	83,030	0.3352	537,949	620,979
1990	4,344,150.31	-50%	2,172,075	44	172,203	3,914	15.98	0.0236	51,301	55,215	109,662	0.3190	692,908	802,570
1991	4,844,431.62	-50%	2,422,216	44	192,034	4,364	16.69	0.0227	54,916	59,281	119,192	0.3030	734,041	853,233
1992	4,100,610.94	-50%	2,050,305	44	162,549	3,694	17.41	0.0218	44,596	48,290	98,231	0.2875	589,487	687,718
1993	4,958,686.59	-50%	2,479,343	44	196,563	4,467	18.15	0.0208	51,677	56,144	115,481	0.2722	674,887	790,367
1994	5,523,451.17	-50%	2,761,726	44	218,950	4,976	18.90	0.0200	55,129	60,105	124,901	0.2573	710,705	835,606
1995	5,640,300.29	-50%	2,820,150	44	223,582	5,081	19.67	0.0191	53,852	58,934	123,631	0.2427	684,550	808,181
1996	7,642,536.21	-50%	3,821,268	44	302,951	6,885	20.44	0.0183	69,803	76,688	162,217	0.2288	874,166	1,036,383
1997	9,565,815.32	-50%	4,782,908	44	379,190	8,618	21.23	0.0175	83,482	92,100	196,231	0.2151	1,028,604	1,224,835
1998	19,391,468.99	-50%	9,695,734	44	768,681	17,470	22.03	0.0167	161,610	179,080	383,816	0.2018	1,956,610	2,340,426
1999	1,622,208.68	-50%	811,104	44	64,305	1,461	22.84	0.0159	12,903	14,365	30,925	0.1890	153,288	184,212
2000	3,079,053.96	-50%	1,539,527	44	122,054	2,774	23.67	0.0152	23,348	26,122	56,395	0.1765	271,667	328,061
2001	13,046,630.51	-50%	6,523,315	44	517,170	11,754	24.50	0.0145	94,310	106,064	229,200	0.1645	1,073,219	1,302,420
2002	496,490.76	-50%	248,245	44	19,681	447	25.35	0.0138	3,417	3,865	8,342	0.1529	37,949	46,291
2003	860,220.03	-50%	430,110	44	34,099	775	26.21	0.0131	5,635	6,410	13,787	0.1416	60,925	74,711
2004	1,329,976.40	-50%	664,988	44	52,720	1,198	27.07	0.0125	8,291	9,489	20,285	0.1310	87,093	107,379
2005	4,082,035.89	-50%	2,041,018	44	161,812	3,678	27.95	0.0119	24,189	27,867	59,025	0.1206	246,100	305,124
2006	2,598,819.60	-50%	1,299,410	44	103,018	2,341	28.84	0.0113	14,630	16,972	35,494	0.1106	143,699	179,194
2007	13,251,425.48	-50%	6,625,713	44	525,288	11,938	29.73	0.0107	70,872	82,810	170,361	0.1011	669,851	840,212
2008	8,880,665.84	-50%	4,440,333	44	352,031	8,001	30.64	0.0102	45,070	53,071	106,889	0.0919	408,005	514,895
2009	3,779,648.61	-50%	1,889,824	44	149,826	3,405	31.55	0.0096	18,202	21,607	42,394	0.0831	157,128	199,522
2010	6,959,022.10	-50%	3,479,511	44	275,857	6,269	32.47	0.0091	31,784	38,053	72,287	0.0748	260,128	332,415
2011	8,894,737.98	-50%	4,447,369	44	352,589	8,013	33.40	0.0087	38,506	46,519	84,942	0.0667	296,747	381,689
2012	8,529,129.58	-50%	4,264,565	44	338,096	7,684	34.34	0.0082	34,977	42,661	74,227	0.0590	251,729	325,957
2013	9,575,207.99	-50%	4,787,604	44	379,563	8,626	35.28	0.0078	37,197	45,823	75,222	0.0517	247,699	322,922
2014	8,511,521.45	-50%	4,255,761	44	337,398	7,668	36.23	0.0074	31,304	38,972	59,581	0.0448	190,488	250,069
2015	10,780,715.96	-50%	5,390,358	44	427,349	9,712	37.19	0.0070	37,516	47,228	66,142	0.0381	205,299	271,441
2016	10,321,458.62	-50%	5,160,729	44	409,144	9,299	38.15	0.0066	33,985	43,284	54,398	0.0318	163,965	218,363
2017	11,191,819.68	-50%	5,595,910	44	443,645	10,083	39.11	0.0062	34,869	44,951	49,305	0.0258	144,357	193,662
2018	15,538,152.07	-50%	7,769,076	44	615,935	13,999	40.08	0.0059	45,779	59,777	54,874	0.0201	156,051	210,925
2019	21,467,511.48	-50%	10,733,756	44	850,975	19,340	41.06	0.0056	59,776	79,116	56,861	0.0146	157,053	213,914
2020	20,971,113.06	-50%	10,485,557	44	831,298	18,893	42.04	0.0053	55,188	74,082	37,031	0.0095	99,368	136,399
2021	21,355,188.74	-50%	10,677,594	44	846,523	19,239	43.02	0.0050	53,114	72,354	18,854	0.0046	49,166	68,021
2022	7,375,638.23	-50%	3,687,819	44	292,371	6,645	43.75	0.0048	17,589	24,234	1,661	0.0012	4,241	5,902
	300,720,151.61		150,360,075.81		11,920,590.13	270,922.50			1,760,246.08	2,031,168.58	3,492,005.29		17,763,154.89	21,255,160.19

Account 368.00 Line Transformers
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1939	270.99	-35%	95	50	5	0	5.01	0.0444	4	4	5	0.6932	66	71
1947	337.03	-35%	118	50	7	0	7.10	0.0394	5	5	6	0.6082	72	77
1948	336.35	-35%	118	50	7	0	7.38	0.0388	5	5	6	0.5976	70	76
1950	868.31	-35%	304	50	17	0	7.96	0.0375	11	12	14	0.5761	175	189
1951	4,523.73	-35%	1,583	50	89	2	8.26	0.0368	58	60	74	0.5652	895	969
1952	9,649.36	-35%	3,377	50	190	4	8.56	0.0362	122	126	157	0.5546	1,873	2,030
1953	59,213.45	-35%	20,725	50	1,163	23	8.86	0.0356	738	761	957	0.5441	11,277	12,234
1954	11,178.62	-35%	3,913	50	220	4	9.17	0.0350	137	141	179	0.5335	2,087	2,267
1955	21,377.60	-35%	7,482	50	420	8	9.49	0.0343	257	265	340	0.5227	3,911	4,251
1956	52,350.33	-35%	18,323	50	1,028	21	9.81	0.0337	617	638	826	0.5122	9,384	10,211
1957	42,701.93	-35%	14,946	50	839	17	10.14	0.0331	494	511	669	0.5015	7,495	8,163
1958	41,583.45	-35%	14,554	50	817	16	10.47	0.0324	472	488	646	0.4910	7,146	7,791
1959	39,120.74	-35%	13,692	50	768	15	10.81	0.0318	436	451	602	0.4804	6,577	7,179
1960	33,616.92	-35%	11,766	50	660	13	11.16	0.0312	367	380	513	0.4696	5,526	6,039
1961	52,455.79	-35%	18,360	50	1,030	21	11.52	0.0305	561	581	793	0.4589	8,424	9,217
1962	32,010.81	-35%	11,204	50	629	13	11.89	0.0299	335	347	479	0.4480	5,019	5,498
1963	56,475.73	-35%	19,767	50	1,109	22	12.26	0.0293	578	601	837	0.4374	8,645	9,482
1964	96,781.14	-35%	33,873	50	1,901	38	12.65	0.0286	969	1,007	1,420	0.4264	14,444	15,864
1965	187,613.70	-35%	65,665	50	3,685	74	13.04	0.0280	1,837	1,911	2,724	0.4157	27,296	30,019
1966	355,336.24	-35%	124,368	50	6,978	140	13.44	0.0273	3,400	3,540	5,103	0.4049	50,361	55,464
1967	309,126.77	-35%	108,194	50	6,071	121	13.86	0.0267	2,887	3,009	4,388	0.3939	42,619	47,007
1968	556,125.38	-35%	194,644	50	10,922	218	14.28	0.0260	5,070	5,289	7,802	0.3832	74,579	82,381
1969	658,350.77	-35%	230,423	50	12,929	259	14.71	0.0254	5,855	6,114	9,126	0.3724	85,811	94,937
1970	484,374.00	-35%	169,531	50	9,513	190	15.15	0.0248	4,200	4,390	6,630	0.3617	61,316	67,947
1971	517,145.06	-35%	181,001	50	10,156	203	15.61	0.0241	4,367	4,570	6,985	0.3508	63,487	70,473
1972	361,920.54	-35%	126,672	50	7,108	142	16.07	0.0235	2,976	3,118	4,823	0.3401	43,083	47,907
1973	498,389.76	-35%	174,436	50	9,788	196	16.55	0.0229	3,987	4,183	6,548	0.3293	57,444	63,992
1974	720,616.95	-35%	252,216	50	14,152	283	17.03	0.0222	5,607	5,890	9,332	0.3188	80,406	89,738
1975	666,340.04	-35%	233,219	50	13,086	262	17.53	0.0216	5,038	5,299	8,498	0.3082	71,867	80,365
1976	799,441.92	-35%	279,805	50	15,700	314	18.04	0.0210	5,869	6,183	10,036	0.2976	83,272	93,307
1977	1,340,682.91	-35%	469,239	50	26,330	527	18.55	0.0204	9,558	10,084	16,561	0.2874	134,843	151,405
1978	1,690,530.24	-35%	591,686	50	33,200	664	19.08	0.0198	11,689	12,353	20,531	0.2770	163,919	184,450
1979	1,352,727.62	-35%	473,455	50	26,566	531	19.62	0.0192	9,067	9,598	16,142	0.2668	126,333	142,475
1980	1,287,528.89	-35%	450,635	50	25,286	506	20.16	0.0186	8,366	8,871	15,091	0.2569	115,787	130,877
1981	1,844,340.01	-35%	645,519	50	36,221	724	20.72	0.0180	11,603	12,327	21,211	0.2470	159,445	180,656
1982	1,950,776.43	-35%	682,772	50	38,311	766	21.29	0.0174	11,876	12,642	21,998	0.2372	161,961	183,960
1983	1,685,030.09	-35%	589,761	50	33,092	662	21.87	0.0168	9,921	10,583	18,618	0.2276	134,213	152,831
1984	2,411,476.80	-35%	844,017	50	47,359	947	22.45	0.0163	13,732	14,679	26,095	0.2183	184,207	210,302
1985	2,314,631.54	-35%	810,121	50	45,457	909	23.05	0.0157	12,733	13,642	24,501	0.2089	169,258	193,759
1986	3,348,837.83	-35%	1,172,093	50	65,768	1,315	23.65	0.0152	17,796	19,111	34,660	0.1999	234,330	268,990
1987	3,986,653.47	-35%	1,395,329	50	78,294	1,566	24.27	0.0147	20,442	22,008	40,290	0.1909	266,426	306,716
1988	4,729,559.94	-35%	1,655,346	50	92,884	1,858	24.89	0.0141	23,400	25,258	46,646	0.1823	301,725	348,371
1989	5,665,301.95	-35%	1,982,856	50	111,261	2,225	25.52	0.0136	27,031	29,256	54,473	0.1738	344,573	399,047
1990	4,077,600.57	-35%	1,427,160	50	80,080	1,602	26.16	0.0131	18,751	20,353	38,182	0.1655	236,131	274,313
1991	2,990,186.41	-35%	1,046,565	50	58,724	1,174	26.81	0.0127	13,245	14,420	27,236	0.1573	164,637	191,873
1992	2,683,717.18	-35%	939,301	50	52,706	1,054	27.47	0.0122	11,444	12,498	23,749	0.1493	140,284	164,033
1993	3,695,898.93	-35%	1,293,565	50	72,584	1,452	28.13	0.0117	15,173	16,624	31,748	0.1417	183,277	215,026
1994	4,421,347.89	-35%	1,547,472	50	86,831	1,737	28.80	0.0113	17,463	19,200	36,816	0.1342	207,663	244,479
1995	20,490,785.85	-35%	7,171,775	50	402,419	8,048	29.48	0.0109	77,826	85,874	165,153	0.1269	909,985	1,075,137
1996	183,271.02	-35%	64,145	50	3,599	72	30.17	0.0104	669	741	1,427	0.1198	7,682	9,109
1997	120,154.01	-35%	42,054	50	2,360	47	30.87	0.0100	421	468	903	0.1128	4,744	5,647
1998	8,865,849.58	-35%	3,103,047	50	174,116	3,482	31.57	0.0096	29,853	33,336	64,179	0.1061	329,314	393,493
1999	305,075.71	-35%	106,776	50	5,991	120	32.27	0.0092	987	1,106	2,125	0.0997	10,647	12,772
2000	1,976,336.78	-35%	691,718	50	38,813	776	32.99	0.0089	6,132	6,908	13,204	0.0934	64,594	77,799
2001	9,837,948.70	-35%	3,443,282	50	193,208	3,864	33.71	0.0085	29,284	33,149	62,947	0.0873	300,629	363,576
2002	202,226.11	-35%	70,779	50	3,972	79	34.43	0.0082	578	657	1,237	0.0815	5,767	7,004
2003	266,077.83	-35%	93,127	50	5,226	105	35.16	0.0078	729	833	1,551	0.0758	7,060	8,611
2004	1,143,356.98	-35%	400,175	50	22,454	449	35.90	0.0075	3,000	3,449	6,332	0.0703	28,136	34,468
2005	1,901,898.48	-35%	665,664	50	37,351	747	36.64	0.0072	4,782	5,529	9,980	0.0650	43,290	53,271
2006	924,068.25	-35%	323,424	50	18,148	363	37.39	0.0069	2,225	2,588	4,577	0.0599	19,377	23,953
2007	6,086,846.05	-35%	2,130,396	50	119,540	2,391	38.14	0.0066	14,038	16,428	28,355	0.0550	117,181	145,536
2008	8,078,958.52	-35%	2,827,635	50	158,663	3,173	38.90	0.0063	17,834	21,007	35,223	0.0502	142,073	177,296
2009	2,599,447.34	-35%	909,807	50	51,051	1,021	39.66	0.0060	5,492	6,513	10,557	0.0457	41,568	52,125
2010	8,119,970.37	-35%	2,841,990	50	159,468	3,189	40.43	0.0058	16,412	19,601	30,522	0.0413	117,293	147,815
2011	10,254,105.21	-35%	3,588,937	50	201,380	4,028	41.20	0.0055	19,826	23,854	35,443	0.0370	132,956	168,399
2012	6,412,076.84	-35%	2,244,227	50	125,927	2,519	41.98	0.0053	11,853	14,371	20,199	0.0330	73,954	94,152
2013	4,271,971.21	-35%	1,495,190	50	83,897	1,678	42.76	0.0050	7,550	9,228	12,148	0.0290	43,419	55,568
2014	4,147,103.37	-35%	1,451,486	50	81,445	1,629	43.55	0.0048	7,003	8,632	10,506	0.0253	36,651	47,158
2015	4,707,380.98	-35%	1,647,583	50	92,448	1,849	44.34	0.0046	7,596	9,445	10,465	0.0216	35,639	46,104
2016	5,010,597.56	-35%	1,753,709	50	98,403	1,968	45.13	0.0044	7,725	9,693	9,584	0.0182	31,869	41,453
2017	5,317,916.65	-35%	1,861,271	50	104,439	2,089	45.93	0.0042	7,830	9,918	8,501	0.0148	27,596	36,097
2018	7,814,819.25	-35%	2,735,187	50	153,475	3,070	46.74	0.0040	10,981	14,051	10,007	0.0116	31,707	41,714
2019	8,016,216.75	-35%	2,805,676	50	157,431	3,149	47.54	0.0038	10,757	13,906	7,746	0.0085	23,969	31,714
2020	8,547,565.30	-35%	2,991,648	50	167,866	3,357	48.36	0.0037	10,941	14,298	5,506	0.0056	16,633	22,139
2021	7,127,753.61	-35%	2,494,714	50	139,982	2,800	49.18	0.0035	8,702	11,502	2,296	0.0027	6,771	9,067
2022	3,651,454.36	-35%	1,278,009	50	71,711	1,434	49.79	0.0034	4,304	5,738	301	0.0007	873	1,174
	204,527,694.78		71,584,693.17		4,016,719.95	80,334.40			645,880.28	726,214.68	1,176,041.64		6,875,021.78	8,051,063.42

Account 369.00 Services
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1953	82,085.86	-125%	102,607	65	2,426	37	7.83	0.0378	3,876	3,913	2,134	0.6133	62,929	65,063
1954	25,790.71	-125%	32,238	65	762	12	8.22	0.0369	1,191	1,202	666	0.5991	19,316	19,981
1956	37,083.33	-125%	46,354	65	1,096	17	9.06	0.0352	1,631	1,648	943	0.5697	26,409	27,353
1957	58,715.17	-125%	73,394	65	1,736	27	9.51	0.0343	2,516	2,543	1,482	0.5545	40,700	42,182
1958	48,636.17	-125%	60,795	65	1,438	22	9.99	0.0334	2,028	2,050	1,217	0.5388	32,755	33,971
1959	52,776.26	-125%	65,970	65	1,560	24	10.49	0.0324	2,138	2,162	1,308	0.5228	34,490	35,798
1960	51,651.76	-125%	64,565	65	1,527	23	11.02	0.0314	2,029	2,053	1,268	0.5064	32,694	33,962
1961	73,561.95	-125%	91,952	65	2,174	33	11.57	0.0304	2,800	2,833	1,787	0.4898	45,042	46,829
1962	78,663.43	-125%	98,329	65	2,325	36	12.15	0.0294	2,896	2,931	1,891	0.4730	46,507	48,397
1963	78,015.59	-125%	97,519	65	2,306	35	12.75	0.0284	2,774	2,810	1,854	0.4561	44,478	46,332
1964	93,427.72	-125%	116,785	65	2,762	42	13.37	0.0275	3,206	3,248	2,194	0.4393	51,299	53,493
1965	106,029.39	-125%	132,537	65	3,134	48	14.01	0.0265	3,507	3,555	2,459	0.4225	55,998	58,456
1966	127,312.49	-125%	159,141	65	3,763	58	14.67	0.0255	4,053	4,111	2,914	0.4059	64,589	67,503
1967	126,118.35	-125%	157,648	65	3,728	57	15.34	0.0245	3,863	3,921	2,848	0.3896	61,420	64,268
1968	285,348.15	-125%	356,685	65	8,434	130	16.02	0.0236	8,405	8,535	6,356	0.3737	133,302	139,658
1969	219,733.13	-125%	274,666	65	6,495	100	16.71	0.0226	6,220	6,320	4,825	0.3582	98,396	103,221
1970	380,272.73	-125%	475,341	65	11,240	173	17.41	0.0218	10,339	10,512	8,230	0.3431	163,111	171,341
1971	533,986.71	-125%	667,483	65	15,784	243	18.12	0.0209	13,936	14,179	11,384	0.3284	219,232	230,616
1972	607,358.53	-125%	759,198	65	17,952	276	18.84	0.0200	15,207	15,484	12,749	0.3141	238,495	251,244
1973	751,171.82	-125%	938,965	65	22,203	342	19.57	0.0192	18,034	18,375	15,518	0.3002	281,905	297,423
1974	744,273.53	-125%	930,342	65	21,999	338	20.32	0.0184	17,112	17,451	15,122	0.2865	266,575	281,697
1975	815,529.02	-125%	1,019,411	65	24,106	371	21.07	0.0176	17,958	18,329	16,292	0.2734	278,725	295,017
1976	878,855.45	-125%	1,098,569	65	25,977	400	21.84	0.0169	18,513	18,912	17,249	0.2605	286,208	303,457
1977	713,647.20	-125%	892,059	65	21,094	325	22.62	0.0161	14,372	14,697	13,753	0.2480	221,268	235,021
1978	810,823.05	-125%	1,013,529	65	23,966	369	23.41	0.0154	15,603	15,971	15,335	0.2360	239,146	254,481
1979	903,294.95	-125%	1,129,119	65	26,700	411	24.22	0.0147	16,590	17,000	16,751	0.2241	253,057	269,808
1980	922,062.39	-125%	1,152,578	65	27,254	419	25.03	0.0140	16,162	16,581	16,759	0.2128	245,295	262,054
1981	1,096,018.59	-125%	1,370,023	65	32,396	498	25.86	0.0134	18,314	18,813	19,508	0.2018	276,446	295,954
1982	697,225.09	-125%	871,531	65	20,609	317	26.69	0.0127	11,107	11,424	12,146	0.1913	166,687	178,833
1983	1,057,132.82	-125%	1,321,416	65	31,247	481	27.54	0.0121	16,035	16,516	18,008	0.1810	239,160	257,167
1984	928,838.50	-125%	1,161,048	65	27,455	422	28.40	0.0115	13,408	13,830	15,459	0.1711	198,651	214,110
1985	870,221.94	-125%	1,087,777	65	25,722	396	29.26	0.0110	11,955	12,350	14,143	0.1617	175,875	190,018
1986	1,027,977.40	-125%	1,284,972	65	30,385	467	30.14	0.0104	13,424	13,891	16,296	0.1525	195,986	212,282
1987	1,039,892.48	-125%	1,299,866	65	30,737	473	31.03	0.0099	12,901	13,374	16,064	0.1437	186,813	202,877
1988	1,345,071.05	-125%	1,681,339	65	39,758	612	31.92	0.0094	15,853	16,464	20,234	0.1354	227,573	247,807
1989	1,704,635.35	-125%	2,130,794	65	50,386	775	32.83	0.0089	19,064	19,840	24,937	0.1272	271,105	296,042
1990	2,066,694.24	-125%	2,583,368	65	61,088	940	33.74	0.0085	21,933	22,873	29,378	0.1195	308,780	338,158
1991	1,609,467.09	-125%	2,011,834	65	47,573	732	34.66	0.0081	16,199	16,931	22,206	0.1121	225,598	247,804
1992	1,700,215.22	-125%	2,125,269	65	50,255	773	35.58	0.0076	16,229	17,002	22,746	0.1051	223,422	246,168
1993	2,364,757.38	-125%	2,955,947	65	69,898	1,075	36.52	0.0072	21,382	22,458	30,626	0.0983	290,684	321,310
1994	1,757,798.05	-125%	2,197,248	65	51,957	799	37.46	0.0069	15,056	15,856	22,014	0.0919	201,946	223,960
1995	1,350,609.22	-125%	1,688,262	65	39,921	614	38.40	0.0065	10,959	11,573	16,337	0.0858	144,882	161,220
1996	2,599,926.16	-125%	3,249,908	65	76,849	1,182	39.35	0.0061	19,972	21,155	30,326	0.0800	259,953	290,279
1997	789,763.83	-125%	987,205	65	23,344	359	40.31	0.0058	5,740	6,100	8,867	0.0744	73,460	82,327
1998	4,959,085.61	-125%	6,198,857	65	146,581	2,255	41.27	0.0055	34,106	36,361	53,513	0.0691	428,565	482,079
1999	16,199.57	-125%	20,249	65	479	7	42.23	0.0052	105	113	168	0.0641	1,299	1,467
2000	288,118.68	-125%	360,148	65	8,516	131	43.20	0.0049	1,773	1,904	2,856	0.0594	21,383	24,239
2001	5,613,507.78	-125%	7,016,885	65	165,925	2,553	44.17	0.0047	32,667	35,220	53,172	0.0549	384,954	438,127
2002	7,587.00	-125%	9,484	65	224	3	45.15	0.0044	42	45	68	0.0506	479	548
2003	11,349.51	-125%	14,187	65	335	5	46.13	0.0042	59	64	97	0.0465	659	757
2004	96,108.09	-125%	120,135	65	2,841	44	47.11	0.0039	472	516	782	0.0426	5,121	5,903
2005	337,224.60	-125%	421,531	65	9,968	153	48.09	0.0037	1,566	1,719	2,593	0.0390	16,436	19,029
2006	46,378.56	-125%	57,973	65	1,371	21	49.08	0.0035	203	224	336	0.0355	2,059	2,395
2007	2,531,030.72	-125%	3,163,788	65	74,813	1,151	50.06	0.0033	10,491	11,642	17,195	0.0323	102,100	119,295
2008	601,410.78	-125%	751,763	65	17,777	273	51.05	0.0031	2,355	2,628	3,815	0.0292	21,930	25,745
2009	713,968.13	-125%	892,460	65	21,104	325	52.04	0.0030	2,640	2,965	4,208	0.0262	23,421	27,629
2010	438,728.95	-125%	548,411	65	12,968	200	53.04	0.0028	1,532	1,731	2,386	0.0235	12,861	15,247
2011	1,084,549.28	-125%	1,355,687	65	32,057	493	54.03	0.0026	3,576	4,070	5,410	0.0208	28,252	33,662
2012	928,868.29	-125%	1,161,085	65	27,456	422	55.02	0.0025	2,893	3,316	4,215	0.0184	21,333	25,549
2013	1,493,452.74	-125%	1,866,816	65	44,144	679	56.02	0.0024	4,391	5,070	6,099	0.0160	29,909	36,007
2014	1,482,599.73	-125%	1,853,250	65	43,823	674	57.02	0.0022	4,115	4,790	5,380	0.0138	25,576	30,956
2015	1,698,228.26	-125%	2,122,785	65	50,196	772	58.01	0.0021	4,453	5,225	5,398	0.0117	24,889	30,287
2016	2,350,254.57	-125%	2,937,818	65	69,469	1,069	59.01	0.0020	5,817	6,886	6,402	0.0097	28,628	35,030
2017	2,560,180.92	-125%	3,200,226	65	75,674	1,164	60.01	0.0019	5,982	7,146	5,809	0.0079	25,203	31,012
2018	2,315,660.48	-125%	2,894,576	65	68,447	1,053	61.00	0.0018	5,111	6,164	4,212	0.0061	17,738	21,950
2019	2,398,695.73	-125%	2,998,370	65	70,901	1,091	62.00	0.0017	4,998	6,088	3,272	0.0045	13,376	16,648
2020	2,975,159.09	-125%	3,718,949	65	87,940	1,353	63.00	0.0016	5,852	7,205	2,706	0.0029	10,739	13,445
2021	2,839,318.15	-125%	3,549,148	65	83,925	1,291	64.00	0.0015	5,272	6,563	1,291	0.0014	4,977	6,268
2022	1,621,455.72	-125%	2,026,820	65	47,927	737	64.75	0.0014	2,883	3,621	184	0.0003	695	880
	73,021,590.19		91,276,987.74			33,205.86			629,844.58	663,050.44				9,189,094.45

Account 370.00 Meters
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1953	13,183.95	-30%	3,955	42	352	8	2.38	0.0517	204	213	332	0.7829	3,097	3,428
1954	6,916.76	-30%	2,075	42	185	4	2.64	0.0509	106	110	173	0.7700	1,598	1,771
1955	7,449.82	-30%	2,235	42	199	5	2.88	0.0502	112	117	185	0.7582	1,694	1,880
1956	19,217.81	-30%	5,765	42	513	12	3.11	0.0496	286	298	475	0.7470	4,307	4,782
1957	12,018.05	-30%	3,605	42	321	8	3.33	0.0489	176	184	295	0.7365	2,655	2,951
1958	15,173.10	-30%	4,552	42	405	10	3.55	0.0483	220	230	371	0.7261	3,305	3,676
1959	19,884.25	-30%	5,965	42	531	13	3.77	0.0477	285	297	483	0.7158	4,270	4,753
1960	18,862.17	-30%	5,659	42	503	12	3.98	0.0471	267	279	456	0.7061	3,996	4,452
1961	15,296.04	-30%	4,589	42	408	10	4.20	0.0466	214	223	367	0.6961	3,194	3,562
1962	3,389.01	-30%	1,017	42	90	2	4.43	0.0459	47	49	81	0.6858	697	778
1963	16,552.35	-30%	4,966	42	442	11	4.66	0.0453	225	236	393	0.6756	3,355	3,748
1964	17,656.51	-30%	5,297	42	471	11	4.89	0.0447	237	248	416	0.6655	3,525	3,942
1965	22,558.27	-30%	6,767	42	602	14	5.13	0.0441	299	313	529	0.6552	4,434	4,962
1966	36,663.30	-30%	10,999	42	978	23	5.37	0.0435	479	502	853	0.6450	7,094	7,947
1967	28,752.31	-30%	8,626	42	767	18	5.62	0.0429	370	388	665	0.6345	5,473	6,137
1968	36,623.60	-30%	10,987	42	977	23	5.88	0.0423	464	488	841	0.6237	6,853	7,693
1969	33,339.84	-30%	10,002	42	890	21	6.14	0.0416	416	438	760	0.6131	6,132	6,892
1970	48,329.92	-30%	14,499	42	1,290	31	6.42	0.0410	594	625	1,093	0.6019	8,727	9,819
1971	46,057.55	-30%	13,817	42	1,229	29	6.70	0.0403	557	586	1,033	0.5908	8,164	9,197
1972	58,980.37	-30%	17,694	42	1,574	37	7.00	0.0396	701	739	1,312	0.5792	10,248	11,560
1973	188,986.94	-30%	56,696	42	5,044	120	7.32	0.0389	2,205	2,325	4,165	0.5670	32,145	36,310
1974	225,229.65	-30%	67,569	42	6,011	143	7.65	0.0382	2,579	2,722	4,916	0.5546	37,475	42,391
1975	130,401.78	-30%	39,121	42	3,480	83	8.00	0.0374	1,463	1,546	2,817	0.5418	21,195	24,012
1976	213,198.36	-30%	63,960	42	5,690	135	8.37	0.0366	2,342	2,477	4,556	0.5285	33,801	38,357
1977	238,819.61	-30%	71,646	42	6,374	152	8.75	0.0358	2,566	2,718	5,046	0.5151	36,905	41,951
1978	270,280.95	-30%	81,084	42	7,213	172	9.16	0.0350	2,837	3,008	5,640	0.5010	40,623	46,264
1979	245,441.43	-30%	73,632	42	6,550	156	9.59	0.0341	2,513	2,669	5,055	0.4866	35,827	40,882
1980	299,881.56	-30%	89,964	42	8,003	191	10.04	0.0333	2,992	3,182	6,090	0.4718	42,449	48,539
1981	402,139.91	-30%	120,642	42	10,733	256	10.51	0.0324	3,905	4,160	8,047	0.4569	55,116	63,163
1982	312,464.32	-30%	93,739	42	8,339	199	11.00	0.0315	2,950	3,148	6,155	0.4417	41,402	47,557
1983	497,832.07	-30%	149,350	42	13,286	316	11.51	0.0306	4,563	4,880	9,645	0.4263	63,668	73,314
1984	499,130.41	-30%	149,739	42	13,321	317	12.04	0.0296	4,438	4,755	9,502	0.4108	61,514	71,017
1985	503,699.90	-30%	151,110	42	13,443	320	12.59	0.0287	4,339	4,659	9,413	0.3952	59,722	69,135
1986	535,338.55	-30%	160,602	42	14,287	340	13.16	0.0278	4,462	4,802	9,811	0.3796	60,961	70,772
1987	553,792.05	-30%	166,138	42	14,780	352	13.74	0.0269	4,464	4,816	9,945	0.3642	60,505	70,450
1988	881,118.78	-30%	264,336	42	23,516	560	14.35	0.0259	6,858	7,418	15,481	0.3485	92,131	107,612
1989	886,382.58	-30%	265,915	42	23,656	563	14.97	0.0250	6,657	7,220	15,224	0.3332	88,599	103,824
1990	861,939.66	-30%	258,582	42	23,004	548	15.61	0.0241	6,239	6,787	14,454	0.3179	82,205	96,659
1991	931,173.55	-30%	279,352	42	24,852	592	16.26	0.0232	6,492	7,084	15,231	0.3030	84,631	99,861
1992	602,950.69	-30%	180,885	42	16,092	383	16.93	0.0224	4,045	4,428	9,605	0.2881	52,116	61,721
1993	818,450.57	-30%	245,535	42	21,843	520	17.61	0.0215	5,279	5,799	12,685	0.2736	67,185	79,870
1994	1,245,957.81	-30%	373,787	42	33,253	792	18.31	0.0207	7,719	8,511	18,756	0.2593	96,922	115,678
1995	4,418,117.65	-30%	1,325,435	42	117,913	2,807	19.02	0.0198	26,276	29,083	64,515	0.2453	325,183	389,698
1996	309,666.31	-30%	92,900	42	8,265	197	19.75	0.0190	1,766	1,963	4,378	0.2316	21,513	25,891
1997	272,099.35	-30%	81,630	42	7,262	173	20.48	0.0182	1,488	1,661	3,721	0.2184	17,826	21,547
1998	3,642,165.05	-30%	1,092,650	42	97,204	2,314	21.23	0.0175	19,071	21,386	48,070	0.2054	224,405	272,475
1999	29,937.95	-30%	8,981	42	799	19	21.99	0.0167	150	169	381	0.1928	1,731	2,112
2000	1,740,589.74	-30%	522,177	42	46,454	1,106	22.76	0.0160	8,345	9,451	21,280	0.1805	94,276	115,556
2001	1,904,634.62	-30%	571,390	42	50,832	1,210	23.54	0.0153	8,731	9,941	22,342	0.1687	96,395	118,737
2002	42,133.15	-30%	12,640	42	1,124	27	24.34	0.0146	184	211	473	0.1571	1,986	2,459
2003	33,815.98	-30%	10,145	42	902	21	25.14	0.0139	141	163	362	0.1460	1,481	1,844
2004	1,681.89	-30%	505	42	45	1	25.95	0.0133	7	8	17	0.1353	68	85
2005	532,763.20	-30%	159,829	42	14,219	339	26.78	0.0127	2,026	2,365	5,153	0.1248	19,952	25,104
2006	131,792.45	-30%	39,538	42	3,517	84	27.61	0.0121	478	562	1,205	0.1148	4,541	5,746
2007	2,644,171.23	-30%	793,251	42	70,569	1,680	28.45	0.0115	9,134	10,815	22,767	0.1052	83,467	106,233
2008	509,037.52	-30%	152,711	42	13,585	323	29.31	0.0110	1,673	1,997	4,105	0.0958	14,635	18,740
2009	693,390.53	-30%	208,017	42	18,506	441	30.17	0.0104	2,169	2,610	5,212	0.0869	18,077	23,290
2010	1,321,242.78	-30%	396,373	42	35,262	840	31.04	0.0099	3,932	4,771	9,202	0.0783	31,038	40,240
2011	1,451,279.33	-30%	435,384	42	38,732	922	31.91	0.0094	4,107	5,030	9,305	0.0701	30,533	39,838
2012	992,941.98	-30%	297,883	42	26,500	631	32.80	0.0090	2,670	3,301	5,805	0.0622	18,522	24,326
2013	1,646,796.31	-30%	494,039	42	43,951	1,046	33.69	0.0085	4,207	5,253	8,696	0.0546	26,986	35,682
2014	946,813.59	-30%	284,044	42	25,269	602	34.59	0.0081	2,296	2,898	4,458	0.0474	13,455	17,913
2015	2,964,263.30	-30%	889,279	42	79,112	1,884	35.50	0.0077	6,822	8,706	12,243	0.0404	35,932	48,176
2016	1,597,954.51	-30%	479,386	42	42,647	1,015	36.41	0.0073	3,490	4,505	5,676	0.0338	16,203	21,879
2017	3,372,298.77	-30%	1,011,690	42	90,002	2,143	37.33	0.0069	6,985	9,128	10,007	0.0275	27,783	37,790
2018	2,779,959.08	-30%	833,988	42	74,193	1,766	38.25	0.0065	5,461	7,227	6,624	0.0215	17,891	24,515
2019	1,282,771.70	-30%	384,832	42	34,235	815	39.18	0.0062	2,388	3,203	2,299	0.0157	6,039	8,338
2020	4,719,566.88	-30%	1,415,870	42	125,958	2,999	40.12	0.0059	8,324	11,323	5,638	0.0102	14,408	20,046
2021	3,498,134.05	-30%	1,049,440	42	93,360	2,223	41.06	0.0056	5,844	8,067	2,089	0.0050	5,195	7,284
2022	1,500,666.88	-30%	450,200	42	40,051	954	41.76	0.0053	2,408	3,362	229	0.0012	558	786
	56,802,201.89		17,040,660.57			36,094.44			238,739.45	274,833.89				3,009,598.44

Account 371.00 Installations on Customers' Premises
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1966	26,215.33	-40%	10,486	30	1,862	62	1.92	0.0531	557	619	1,743	0.7177	7,526	9,269
1967	13,724.01	-40%	5,490	30	975	32	2.38	0.0517	284	316	898	0.6943	3,811	4,709
1968	33,299.17	-40%	13,320	30	2,366	79	2.83	0.0504	671	750	2,142	0.6720	8,950	11,093
1969	23,854.83	-40%	9,542	30	1,695	56	3.26	0.0491	469	525	1,510	0.6512	6,214	7,724
1970	16,811.88	-40%	6,725	30	1,194	40	3.68	0.0480	323	362	1,048	0.6314	4,246	5,294
1971	7,076.82	-40%	2,831	30	503	17	4.10	0.0468	133	149	434	0.6120	1,732	2,167
1972	32,952.90	-40%	13,181	30	2,341	78	4.50	0.0458	603	681	1,990	0.5940	7,830	9,820
1973	24,712.67	-40%	9,885	30	1,756	59	4.90	0.0447	442	501	1,469	0.5765	5,698	7,167
1974	12,294.21	-40%	4,918	30	873	29	5.30	0.0437	215	244	719	0.5593	2,750	3,469
1975	11,544.00	-40%	4,618	30	820	27	5.70	0.0427	197	225	664	0.5425	2,505	3,169
1976	9,337.57	-40%	3,735	30	663	22	6.10	0.0417	156	178	528	0.5261	1,965	2,493
1977	15,907.68	-40%	6,363	30	1,130	38	6.49	0.0408	260	297	886	0.5105	3,248	4,134
1978	6,706.70	-40%	2,683	30	476	16	6.89	0.0399	107	123	367	0.4948	1,327	1,694
1979	13,315.88	-40%	5,326	30	946	32	7.29	0.0390	208	239	716	0.4795	2,554	3,270
1980	42,591.34	-40%	17,037	30	3,026	101	7.69	0.0381	649	750	2,250	0.4645	7,914	10,164
1981	18,228.08	-40%	7,291	30	1,295	43	8.10	0.0372	271	314	945	0.4495	3,278	4,223
1982	46,927.20	-40%	18,771	30	3,334	111	8.51	0.0363	682	793	2,388	0.4349	8,163	10,551
1983	24,625.43	-40%	9,850	30	1,749	58	8.93	0.0355	349	408	1,229	0.4202	4,139	5,368
1984	38,073.98	-40%	15,230	30	2,705	90	9.35	0.0346	527	617	1,862	0.4059	6,182	8,044
1985	43,076.82	-40%	17,231	30	3,060	102	9.77	0.0338	582	684	2,064	0.3920	6,754	8,818
1986	29,585.22	-40%	11,834	30	2,102	70	10.21	0.0329	390	460	1,386	0.3777	4,470	5,857
1987	8,662.35	-40%	3,465	30	615	21	10.65	0.0321	111	132	397	0.3638	1,261	1,658
1988	8,253.80	-40%	3,302	30	586	20	11.09	0.0313	103	123	370	0.3503	1,156	1,526
1989	14,941.20	-40%	5,976	30	1,061	35	11.55	0.0305	182	218	653	0.3365	2,011	2,664
1990	7,944.02	-40%	3,178	30	564	19	12.01	0.0297	94	113	338	0.3230	1,026	1,365
1991	21,569.24	-40%	8,628	30	1,532	51	12.48	0.0289	249	300	895	0.3097	2,672	3,567
1992	6,519.20	-40%	2,608	30	463	15	12.95	0.0281	73	89	263	0.2967	774	1,037
1993	9,120.15	-40%	3,648	30	648	22	13.44	0.0273	100	121	358	0.2835	1,034	1,392
1994	11,542.45	-40%	4,617	30	820	27	13.93	0.0266	123	150	439	0.2706	1,249	1,689
1995	3,116.27	-40%	1,247	30	221	7	14.43	0.0258	32	40	115	0.2579	321	436
1996	9,632.96	-40%	3,853	30	684	23	14.93	0.0251	97	119	344	0.2455	946	1,290
1997	238.97	-40%	96	30	17	1	15.45	0.0244	2	3	8	0.2330	22	31
1998	104,113.25	-40%	41,645	30	7,396	247	15.97	0.0236	984	1,231	3,459	0.2209	9,200	12,659
1999	92.63	-40%	37	30	7	0	16.50	0.0229	1	1	3	0.2089	8	11
2000	19,509.70	-40%	7,804	30	1,386	46	17.04	0.0222	173	220	599	0.1971	1,538	2,137
2001	229,444.18	-40%	91,778	30	16,299	543	17.58	0.0215	1,977	2,520	6,748	0.1856	17,036	23,784
2003	3,292.21	-40%	1,317	30	234	8	18.69	0.0202	27	34	88	0.1631	215	303
2004	3,919.88	-40%	1,568	30	278	9	19.25	0.0196	31	40	100	0.1523	239	339
2005	17,892.61	-40%	7,157	30	1,271	42	19.82	0.0189	135	178	431	0.1416	1,014	1,445
2006	588.70	-40%	235	30	42	1	20.39	0.0183	4	6	13	0.1313	31	44
2007	23,249.73	-40%	9,300	30	1,652	55	20.97	0.0177	165	220	497	0.1212	1,127	1,624
2008	247,902.43	-40%	99,161	30	17,610	587	21.55	0.0171	1,699	2,286	4,960	0.1114	11,043	16,004
2009	27,317.07	-40%	10,927	30	1,941	65	22.14	0.0166	181	246	508	0.1017	1,111	1,620
2010	106,873.86	-40%	42,750	30	7,592	253	22.73	0.0160	684	937	1,840	0.0924	3,949	5,789
2011	302,423.70	-40%	120,969	30	21,484	716	23.32	0.0155	1,872	2,588	4,784	0.0834	10,083	14,867
2012	2,371.54	-40%	949	30	168	6	23.92	0.0149	14	20	34	0.0745	71	105
2013	14,520.85	-40%	5,808	30	1,032	34	24.51	0.0144	84	118	189	0.0661	384	573
2014	83,158.70	-40%	33,263	30	5,907	197	25.11	0.0140	464	661	963	0.0578	1,922	2,885
2015	56,616.95	-40%	22,647	30	4,022	134	25.72	0.0135	305	439	574	0.0497	1,125	1,698
2016	31,141.74	-40%	12,457	30	2,212	74	26.32	0.0130	162	236	271	0.0419	522	794
2017	19,130.97	-40%	7,652	30	1,359	45	26.93	0.0126	96	141	139	0.0344	263	402
2018	22,106.96	-40%	8,843	30	1,570	52	27.54	0.0121	107	160	129	0.0270	239	368
2019	39,878.17	-40%	15,951	30	2,833	94	28.15	0.0117	187	281	175	0.0200	319	493
2020	35,399.12	-40%	14,160	30	2,515	84	28.76	0.0113	160	244	104	0.0132	186	290
2021	170,525.77	-40%	68,210	30	12,114	404	29.38	0.0109	744	1,148	250	0.0065	440	691
2022	11,449.09	-40%	4,580	30	813	27	29.84	0.0106	49	76	4	0.0016	8	12
	2,165,322.14		866,128.86			5,127.34			19,546.78	24,674.12				234,084.92

Account 373.10 Street Lighting and Signal Systems
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1945	530.06	-45%	239	44	19	0	3.80	0.0476	11	12	17	0.7241	173	190
1953	1,267.86	-45%	571	44	45	1	6.48	0.0408	23	24	39	0.6092	348	386
1954	1,314.23	-45%	591	44	47	1	6.82	0.0400	24	25	40	0.5958	352	392
1955	877.32	-45%	395	44	31	1	7.16	0.0393	15	16	26	0.5827	230	256
1956	1,318.89	-45%	594	44	47	1	7.51	0.0385	23	24	39	0.5695	338	377
1957	405.56	-45%	183	44	14	0	7.85	0.0377	7	7	12	0.5569	102	114
1959	148.29	-45%	67	44	5	0	8.55	0.0362	2	3	4	0.5318	35	40
1960	4,039.12	-45%	1,818	44	144	3	8.90	0.0355	65	68	115	0.5196	944	1,059
1961	183.27	-45%	82	44	7	0	9.25	0.0348	3	3	5	0.5076	42	47
1962	141.68	-45%	64	44	5	0	9.61	0.0341	2	2	4	0.4956	32	36
1963	1,140.62	-45%	513	44	41	1	9.97	0.0334	17	18	31	0.4838	248	280
1964	192.65	-45%	87	44	7	0	10.33	0.0327	3	3	5	0.4722	41	46
1965	267.87	-45%	121	44	10	0	10.70	0.0320	4	4	7	0.4606	56	63
1966	28,023.49	-45%	12,611	44	1,000	23	11.07	0.0313	395	418	748	0.4492	5,665	6,413
1967	27,884.01	-45%	12,548	44	995	23	11.44	0.0307	385	408	736	0.4381	5,497	6,233
1968	28,764.24	-45%	12,944	44	1,026	23	11.82	0.0300	389	412	751	0.4269	5,525	6,276
1969	23,448.46	-45%	10,552	44	837	19	12.20	0.0294	310	329	605	0.4159	4,389	4,993
1970	14,004.11	-45%	6,302	44	500	11	12.58	0.0287	181	192	357	0.4052	2,553	2,910
1971	40,110.71	-45%	18,050	44	1,431	33	12.97	0.0281	507	540	1,009	0.3944	7,119	8,128
1972	29,705.99	-45%	13,368	44	1,060	24	13.36	0.0275	367	391	738	0.3839	5,132	5,870
1973	54,938.79	-45%	24,722	44	1,960	45	13.76	0.0268	664	708	1,347	0.3733	9,230	10,577
1974	52,831.79	-45%	23,774	44	1,885	43	14.16	0.0262	624	666	1,278	0.3630	8,631	9,909
1975	55,293.70	-45%	24,882	44	1,973	45	14.56	0.0256	638	683	1,320	0.3530	8,782	10,102
1976	26,639.25	-45%	11,988	44	950	22	14.97	0.0250	300	322	627	0.3429	4,110	4,737
1977	53,698.36	-45%	24,164	44	1,916	44	15.39	0.0244	590	634	1,246	0.3328	8,041	9,287
1978	53,783.99	-45%	24,203	44	1,919	44	15.81	0.0239	577	621	1,229	0.3229	7,816	9,045
1979	37,091.77	-45%	16,691	44	1,323	30	16.24	0.0233	388	418	835	0.3131	5,226	6,061
1980	77,000.35	-45%	34,650	44	2,747	62	16.67	0.0227	786	849	1,706	0.3035	10,516	12,222
1981	55,375.76	-45%	24,919	44	1,976	45	17.11	0.0221	551	596	1,207	0.2939	7,324	8,531
1982	61,314.10	-45%	27,591	44	2,187	50	17.55	0.0216	595	645	1,315	0.2846	7,852	9,166
1983	48,353.29	-45%	21,759	44	1,725	39	18.00	0.0210	457	497	1,019	0.2753	5,989	7,009
1984	58,104.21	-45%	26,147	44	2,073	47	18.46	0.0205	535	582	1,203	0.2660	6,955	8,158
1985	84,378.58	-45%	37,970	44	3,010	68	18.93	0.0199	757	825	1,715	0.2568	9,749	11,464
1986	135,709.32	-45%	61,069	44	4,842	110	19.40	0.0194	1,184	1,294	2,707	0.2478	15,132	17,839
1987	97,331.79	-45%	43,799	44	3,472	79	19.88	0.0189	826	905	1,904	0.2389	10,462	12,366
1988	199,207.65	-45%	89,643	44	7,107	162	20.36	0.0184	1,645	1,807	3,818	0.2302	20,635	24,453
1989	250,124.97	-45%	112,556	44	8,923	203	20.86	0.0178	2,007	2,210	4,693	0.2214	24,920	29,613
1990	172,187.78	-45%	77,485	44	6,143	140	21.36	0.0173	1,342	1,482	3,161	0.2129	16,494	19,654
1991	400,612.06	-45%	180,275	44	14,292	325	21.87	0.0168	3,033	3,358	7,188	0.2044	36,849	44,037
1992	331,698.71	-45%	149,264	44	11,834	269	22.39	0.0163	2,437	2,706	5,812	0.1960	29,261	35,073
1993	443,869.69	-45%	199,741	44	15,836	360	22.92	0.0158	3,163	3,523	7,587	0.1878	37,502	45,089
1994	448,716.20	-45%	201,922	44	16,008	364	23.46	0.0154	3,100	3,463	7,473	0.1796	36,260	43,733
1995	607,702.32	-45%	273,466	44	21,680	493	24.01	0.0149	4,067	4,560	9,850	0.1715	46,900	56,749
1996	551,979.75	-45%	248,391	44	19,693	448	24.57	0.0144	3,577	4,024	8,696	0.1635	40,622	49,318
1997	1,426,809.01	-45%	642,064	44	50,903	1,157	25.14	0.0139	8,947	10,103	21,819	0.1557	99,966	121,785
1998	1,926,769.80	-45%	867,046	44	68,740	1,562	25.72	0.0135	11,684	13,247	28,558	0.1480	128,300	156,859
1999	39,686.74	-45%	17,859	44	1,416	32	26.31	0.0130	233	265	569	0.1404	2,507	3,076
2000	309,954.60	-45%	139,480	44	11,058	251	26.91	0.0126	1,755	2,006	4,295	0.1329	18,539	22,834
2001	2,804,611.74	-45%	1,262,075	44	100,058	2,274	27.53	0.0121	15,324	17,598	37,453	0.1255	158,354	195,808
2002	137,986.85	-45%	62,094	44	4,923	112	28.15	0.0117	727	839	1,773	0.1183	7,345	9,118
2003	112,173.02	-45%	50,478	44	4,002	91	28.79	0.0113	570	661	1,383	0.1111	5,610	6,993
2004	83,541.94	-45%	37,594	44	2,980	68	29.45	0.0109	409	476	986	0.1040	3,911	4,897
2005	117,059.23	-45%	52,677	44	4,176	95	30.11	0.0105	551	646	1,318	0.0972	5,120	6,438
2006	225,217.39	-45%	101,348	44	8,035	183	30.79	0.0101	1,020	1,202	2,412	0.0904	9,163	11,575
2007	646,657.28	-45%	290,996	44	23,070	524	31.49	0.0097	2,813	3,337	6,559	0.0837	24,358	30,918
2008	1,590,374.45	-45%	715,669	44	56,738	1,290	32.20	0.0093	6,640	7,929	15,216	0.0772	55,231	70,448
2009	338,019.73	-45%	152,109	44	12,059	274	32.93	0.0089	1,353	1,627	3,034	0.0707	10,759	13,793
2010	2,073,595.14	-45%	933,118	44	73,978	1,681	33.67	0.0085	7,954	9,636	17,368	0.0645	60,159	77,527
2011	5,399,003.36	-45%	2,429,552	44	192,616	4,378	34.42	0.0082	19,835	24,212	41,938	0.0584	141,867	183,804
2012	854,765.12	-45%	384,644	44	30,495	693	35.20	0.0078	3,002	3,695	6,099	0.0523	20,133	26,232
2013	617,115.89	-45%	277,702	44	22,016	500	35.99	0.0075	2,071	2,571	4,008	0.0465	12,909	16,917
2014	698,792.88	-45%	314,457	44	24,930	567	36.80	0.0071	2,238	2,805	4,079	0.0408	12,815	16,895
2015	1,141,356.99	-45%	513,611	44	40,719	925	37.63	0.0068	3,485	4,411	5,895	0.0351	18,053	23,948
2016	838,710.76	-45%	377,420	44	29,922	680	38.48	0.0065	2,439	3,119	3,754	0.0297	11,202	14,956
2017	865,476.03	-45%	389,464	44	30,877	702	39.34	0.0061	2,395	3,097	3,270	0.0244	9,508	12,778
2018	848,721.28	-45%	381,925	44	30,279	688	40.23	0.0058	2,231	2,919	2,594	0.0192	7,345	9,939
2019	1,044,014.86	-45%	469,807	44	37,246	847	41.14	0.0055	2,604	3,451	2,421	0.0142	6,671	9,092
2020	1,175,386.54	-45%	528,924	44	41,933	953	42.07	0.0053	2,779	3,732	1,839	0.0093	4,931	6,771
2021	1,145,187.49	-45%	515,334	44	40,856	929	43.02	0.0050	2,563	3,492	910	0.0046	2,373	3,283
2022	533,656.40	-45%	240,145	44	19,039	433	43.75	0.0048	1,145	1,578	108	0.0012	276	384
	31,556,357.13		14,200,360.71			25,586.56			143,345.45	168,932.01				1,595,370.36

Account 390.10 Structures and Improvements
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1911	38,668.75	-15%	5,800	60	183	3	0.30	0.0583	338	341	182	0.9513	5,518	5,700
1920	9,845.61	-15%	1,477	60	47	1	2.48	0.0514	76	77	45	0.8353	1,234	1,278
1941	1,653.26	-15%	248	60	8	0	8.58	0.0362	9	9	7	0.5785	143	150
1953	1,162.16	-15%	174	60	5	0	12.71	0.0285	5	5	4	0.4493	78	83
1955	4,274.73	-15%	641	60	20	0	13.51	0.0272	17	18	16	0.4277	274	290
1956	4,668.83	-15%	700	60	22	0	13.92	0.0266	19	19	17	0.4169	292	309
1957	24.58	-15%	4	60	0	0	14.34	0.0260	0	0	0	0.4062	1	2
1958	300,339.19	-15%	45,051	60	1,421	24	14.77	0.0253	1,141	1,165	1,071	0.3955	17,818	18,889
1959	5,938.00	-15%	891	60	28	0	15.22	0.0247	22	22	21	0.3846	343	364
1963	494.79	-15%	74	60	2	0	17.08	0.0222	2	2	2	0.3423	25	27
1965	403,662.54	-15%	60,549	60	1,910	32	18.07	0.0209	1,268	1,300	1,335	0.3216	19,471	20,805
1966	37,967.07	-15%	5,695	60	180	3	18.58	0.0203	116	119	124	0.3113	1,773	1,897
1967	160,516.33	-15%	24,077	60	759	13	19.10	0.0197	475	488	518	0.3012	7,253	7,770
1968	313.87	-15%	47	60	1	0	19.63	0.0191	1	1	1	0.2912	14	15
1969	4,956.08	-15%	743	60	23	0	20.17	0.0186	14	14	16	0.2813	209	225
1973	51,507.04	-15%	7,726	60	244	4	22.43	0.0163	126	130	153	0.2431	1,879	2,031
1974	97,601.93	-15%	14,640	60	462	8	23.02	0.0157	230	238	285	0.2340	3,425	3,710
1977	19,915.67	-15%	2,987	60	94	2	24.83	0.0142	42	44	55	0.2077	620	676
1978	21,136.90	-15%	3,171	60	100	2	25.46	0.0137	43	45	58	0.1991	631	689
1979	32,599.18	-15%	4,890	60	154	3	26.09	0.0132	65	67	87	0.1909	934	1,021
1980	244,857.83	-15%	36,729	60	1,158	19	26.73	0.0127	467	486	642	0.1829	6,717	7,359
1981	58,772.42	-15%	8,816	60	278	5	27.39	0.0122	108	113	151	0.1749	1,542	1,693
1982	11,568.71	-15%	1,735	60	55	1	28.04	0.0118	20	21	29	0.1673	290	319
1983	19,601.15	-15%	2,940	60	93	2	28.71	0.0113	33	35	48	0.1598	470	518
1984	67,308.39	-15%	10,096	60	318	5	29.39	0.0109	110	115	162	0.1524	1,539	1,701
1985	126,025.40	-15%	18,904	60	596	10	30.07	0.0105	198	208	297	0.1453	2,747	3,045
1986	237,695.32	-15%	35,654	60	1,125	19	30.76	0.0101	359	378	548	0.1384	4,936	5,484
1987	726,440.54	-15%	108,966	60	3,437	57	31.46	0.0097	1,055	1,112	1,635	0.1317	14,354	15,989
1988	2,359,460.61	-15%	353,919	60	11,163	186	32.17	0.0093	3,289	3,475	5,178	0.1252	44,306	49,483
1989	1,208,748.08	-15%	181,312	60	5,719	95	32.88	0.0089	1,618	1,713	2,585	0.1189	21,559	24,144
1990	1,715,638.00	-15%	257,346	60	8,117	135	33.61	0.0086	2,201	2,337	3,570	0.1127	29,005	32,575
1991	1,050,006.97	-15%	157,501	60	4,968	83	34.33	0.0082	1,293	1,375	2,125	0.1068	16,829	18,954
1992	1,011,394.30	-15%	151,709	60	4,785	80	35.07	0.0079	1,193	1,273	1,988	0.1011	15,334	17,322
1993	908,371.68	-15%	136,256	60	4,298	72	35.82	0.0075	1,026	1,098	1,732	0.0955	13,008	14,740
1994	227,320.87	-15%	34,098	60	1,075	18	36.57	0.0072	246	264	420	0.0901	3,072	3,492
1995	280,870.13	-15%	42,131	60	1,329	22	37.32	0.0069	291	313	502	0.0850	3,579	4,081
1996	22,147.88	-15%	3,322	60	105	2	38.09	0.0066	22	24	38	0.0799	265	304
1997	125,276.70	-15%	18,792	60	593	10	38.86	0.0063	119	129	209	0.0751	1,411	1,619
1998	333,021.74	-15%	49,953	60	1,576	26	39.64	0.0060	302	328	535	0.0704	3,516	4,050
1999	102,467.31	-15%	15,370	60	485	8	40.42	0.0058	89	97	158	0.0659	1,013	1,171
2000	138,129.55	-15%	20,719	60	653	11	41.21	0.0055	114	125	205	0.0616	1,276	1,480
2001	1,810,011.58	-15%	271,502	60	8,563	143	42.01	0.0053	1,431	1,574	2,568	0.0574	15,576	18,144
2002	819,274.78	-15%	122,891	60	3,876	65	42.81	0.0050	619	683	1,110	0.0534	6,558	7,669
2003	6,426.71	-15%	964	60	30	1	43.62	0.0048	5	5	8	0.0495	48	56
2004	477,453.38	-15%	71,618	60	2,259	38	44.43	0.0046	328	366	586	0.0458	3,280	3,866
2005	38,844.06	-15%	5,827	60	184	3	45.25	0.0044	25	29	45	0.0422	246	291
2006	404,591.13	-15%	60,689	60	1,914	32	46.08	0.0042	253	285	444	0.0388	2,354	2,798
2007	412,482.86	-15%	61,872	60	1,951	33	46.91	0.0040	246	279	426	0.0355	2,197	2,622
2008	180,274.08	-15%	27,041	60	853	14	47.75	0.0038	102	117	174	0.0323	874	1,049
2009	649,117.41	-15%	97,368	60	3,071	51	48.59	0.0036	351	403	584	0.0293	2,855	3,439
2010	21,925.94	-15%	3,289	60	104	2	49.44	0.0034	11	13	18	0.0264	87	105
2011	289,354.72	-15%	43,403	60	1,369	23	50.29	0.0033	142	165	222	0.0236	1,026	1,248
2012	2,144,343.10	-15%	321,651	60	10,145	169	51.15	0.0031	1,002	1,171	1,496	0.0210	6,746	8,243
2013	263,507.52	-15%	39,526	60	1,247	21	52.02	0.0030	117	138	166	0.0184	728	893
2014	502,789.16	-15%	75,418	60	2,379	40	52.88	0.0028	213	252	282	0.0160	1,206	1,488
2015	746,600.13	-15%	111,990	60	3,532	59	53.76	0.0027	300	359	367	0.0136	1,528	1,895
2016	2,964,558.39	-15%	444,684	60	14,025	234	54.64	0.0025	1,133	1,366	1,253	0.0114	5,074	6,327
2017	454,557.99	-15%	68,184	60	2,151	36	55.52	0.0024	165	201	161	0.0093	633	794
2018	1,422,897.66	-15%	213,435	60	6,732	112	56.41	0.0023	491	603	403	0.0072	1,547	1,949
2019	967,379.64	-15%	145,107	60	4,577	76	57.30	0.0022	317	393	206	0.0053	770	976
2020	558,979.55	-15%	83,847	60	2,645	44	58.19	0.0021	174	218	80	0.0035	291	370
2021	30,575.90	-15%	4,586	60	145	2	59.10	0.0020	9	11	2	0.0017	8	10
2022	60,248.17	-15%	9,037	60	285	5	59.77	0.0019	17	22	1	0.0004	4	5
	27,398,563.95		4,109,784.59			2,160.38			25,615.13	27,775.51				339,690.53

Account 392.00 Transportation Equipment
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1987	58,919.69	20%	(11,784)	13	(5,572)	-429	0.38	0.0580	(684)	(1,112)	(5,410)	0.5055	(5,956)	(11,366)
1989	228,694.96	20%	(45,739)	13	(21,629)	-1,664	0.72	0.0569	(2,602)	(4,266)	(20,431)	0.4865	(22,251)	(42,683)
1990	196,069.35	20%	(39,214)	13	(18,544)	-1,426	0.89	0.0563	(2,209)	(3,636)	(17,274)	0.4771	(18,710)	(35,984)
1991	40,036.61	20%	(8,007)	13	(3,787)	-291	1.07	0.0558	(446)	(738)	(3,475)	0.4673	(3,742)	(7,217)
2003	347,301.90	20%	(69,460)	13	(32,847)	-2,527	3.58	0.0482	(3,351)	(5,878)	(23,801)	0.3408	(23,669)	(47,470)
2004	8,496.99	20%	(1,699)	13	(804)	-62	3.83	0.0476	(81)	(143)	(567)	0.3291	(559)	(1,126)
2005	107,854.93	20%	(21,571)	13	(10,201)	-785	4.08	0.0469	(1,011)	(1,796)	(6,999)	0.3177	(6,852)	(13,851)
2009	42,698.00	20%	(8,540)	13	(4,038)	-311	5.06	0.0443	(378)	(689)	(2,466)	0.2743	(2,342)	(4,809)
2012	130,867.46	20%	(26,173)	13	(12,377)	-952	5.85	0.0423	(1,108)	(2,060)	(6,807)	0.2410	(6,308)	(13,116)
2013	53,705.53	20%	(10,741)	13	(5,079)	-391	6.19	0.0415	(446)	(837)	(2,661)	0.2272	(2,440)	(5,101)
2014	389,562.57	20%	(77,913)	13	(36,843)	-2,834	6.60	0.0405	(3,159)	(5,993)	(18,138)	0.2108	(16,426)	(34,565)
2015	213,568.14	20%	(42,714)	13	(20,199)	-1,554	7.11	0.0394	(1,682)	(3,235)	(9,151)	0.1910	(8,160)	(17,311)
2016	51,502.56	20%	(10,301)	13	(4,871)	-375	7.73	0.0380	(391)	(766)	(1,975)	0.1677	(1,728)	(3,702)
2017	392,578.98	20%	(78,516)	13	(37,129)	-2,856	8.45	0.0364	(2,862)	(5,718)	(12,995)	0.1417	(11,127)	(24,122)
2018	19,290.33	20%	(3,858)	13	(1,824)	-140	9.26	0.0348	(134)	(275)	(525)	0.1137	(439)	(964)
2019	1,160,951.80	20%	(232,190)	13	(109,799)	-8,446	10.13	0.0331	(7,682)	(16,128)	(24,240)	0.0850	(19,741)	(43,981)
2020	468,981.59	20%	(93,796)	13	(44,355)	-3,412	11.04	0.0314	(2,945)	(6,357)	(6,687)	0.0565	(5,302)	(11,989)
2021	391,828.48	20%	(78,366)	13	(37,058)	-2,851	12.01	0.0297	(2,326)	(5,177)	(2,822)	0.0278	(2,175)	(4,997)
2022	125,567.19	20%	(25,113)	13	(11,876)	-914	12.75	0.0284	(714)	(1,628)	(228)	0.0069	(172)	(401)
	4,428,477.06		(885,695.41)			(32,217.69)			(34,211.99)	(66,429.68)				(324,754.35)

Account 396.00 Power Operated Equipment
Calculation of Present Value Based Cost of Removal

Year	Original Cost 6/30/2022	Estimated Future Cost of Removal %	Estimated Future Cost of Removal Amount	Average Service Life	Discounted Removal Cost 5.930%	Annual Depreciation of Removal Cost	Average Remaining Life	Increment Factor in 2022 at 5.930%	Increment in Removal Cost 2022	Total Annual Depreciation Expense	Calculated Accrued Depreciation for Cost of Removal	Calculated Accrued Accretion Factor	Calculated Accrued Accretion for Cost of Removal	Theoretical Reserve
a	b	c	d=b*-c	e	f=d/((1+0.05930)^e)	g=f/e	h	i	j=d*k	k=g+j	l	m	n=d*m	o=l+n
1987	34,948.48	5%	(1,747)	20	(552)	-28	1.73	0.0537	(94)	(121)	(504)	0.5892	(1,030)	(1,534)
1988	16,086.55	5%	(804)	20	(254)	-13	2.06	0.0527	(42)	(55)	(228)	0.5721	(460)	(688)
1989	395,850.64	5%	(19,793)	20	(6,253)	-313	2.40	0.0516	(1,022)	(1,335)	(5,503)	0.5549	(10,983)	(16,486)
1990	101,018.50	5%	(5,051)	20	(1,596)	-80	2.73	0.0507	(256)	(336)	(1,378)	0.5385	(2,720)	(4,098)
1992	42,051.15	5%	(2,103)	20	(664)	-33	3.41	0.0487	(102)	(136)	(551)	0.5057	(1,063)	(1,614)
2005	4,137.27	5%	(207)	20	(65)	-3	8.52	0.0363	(8)	(11)	(38)	0.2962	(61)	(99)
2012	126,309.90	5%	(6,315)	20	(1,995)	-100	12.23	0.0293	(185)	(285)	(775)	0.1784	(1,127)	(1,902)
2013	7,821.55	5%	(391)	20	(124)	-6	12.85	0.0283	(11)	(17)	(44)	0.1610	(63)	(107)
2015	101,796.87	5%	(5,090)	20	(1,608)	-80	14.19	0.0262	(133)	(214)	(467)	0.1256	(639)	(1,106)
2017	14,023.84	5%	(701)	20	(222)	-11	15.65	0.0241	(17)	(28)	(48)	0.0900	(63)	(111)
2020	345.84	5%	(17)	20	(5)	0	18.12	0.0209	(0)	(1)	(1)	0.0361	(1)	(1)
2021	176.12	5%	(9)	20	(3)	0	19.04	0.0198	(0)	(0)	(0)	0.0180	(0)	(0)
2022	105.04	5%	(5)	20	(2)	0	19.75	0.0190	(0)	(0)	(0)	0.0046	(0)	(0)
	844,671.75		(42,233.59)			(667.19)			(1,871.16)	(2,538.35)				(27,747.65)

THE POTOMAC EDISON COMPANY

COMPARISON OF CURRENTLY APPROVED AND PROPOSED SURVIVOR CURVES, NET SALVAGE PERCENTS AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF JUNE 30, 2022

			CURRENTLY APPROVED				PROPOSED				
		ORIGINAL COST		NET	CALCULATED ANNUAL			NET	CALCULATED ANNUAL		
	ACCOUNT	AS OF JUNE 30, 2022	SURVIVOR CURVE	SALVAGE PERCENT	ACCRUAL AMOUNT	ACCRUAL RATE	SURVIVOR CURVE	SALVAGE PERCENT	ACCRUAL AMOUNT	ACCRUAL RATE	INCREASE (DECREASE)
	(1)	(2)	(3)	(4)	(5)=(6)*(2)	(6)	(7)	(8)	(9)	(10)	(11)=(9)-(5)
	ELECTRIC PLANT										
	INTANGIBLE PLANT										
303.00	MISCELLANEOUS INTANGIBLE PLANT	25,518,930.61	7-SQ	0	3,151,588	12.35	7-SQ	0	1,839,674	7.21	(1,311,914)
	TOTAL INTANGIBLE PLANT	**25,518,930.61**			**3,151,588**	**12.35**			**1,839,674**	**7.21**	**(1,311,914)**
	DISTRIBUTION PLANT										
360.20	LAND AND LAND RIGHTS - EASEMENTS	10,999,110.61	75-R3	0	144,088	1.31	75-R3	0	143,090	1.30	(998)
361.00	STRUCTURES AND IMPROVEMENTS	11,344,560.25	65-S4	(20)	136,135	1.20	65-S4	(20)	144,001	1.27	7,867
362.00	STATION EQUIPMENT	186,933,531.24	75-R1.5	(15)	2,018,882	1.08	65-R2.5	(20)	2,532,124	1.35	513,241
364.00	POLES, TOWERS AND FIXTURES	131,651,738.90	76-R4	(120)	1,711,473	1.30	70-R4	(125)	2,384,226	1.81	672,753
365.00	OVERHEAD CONDUCTORS AND DEVICES	151,495,917.54	76-R0.5	(80)	2,333,037	1.54	62-R1	(100)	3,066,725	2.02	733,688
365.10	OVERHEAD CONDUCTORS AND DEVICES - CLEARING	77,713,677.02	70-R4	0	948,107	1.22	70-R4	0	969,012	1.25	20,905
366.00	UNDERGROUND CONDUIT	66,754,673.86	65-R4	(40)	954,592	1.43	65-R4	(50)	1,080,369	1.62	125,777
367.00	UNDERGROUND CONDUCTORS AND DEVICES	300,720,151.63	46-R2.5	(40)	8,089,372	2.69	44-R3	(50)	9,719,926	3.23	1,630,554
368.00	LINE TRANSFORMERS	204,527,694.80	48-R1.5	(35)	3,722,404	1.82	50-R1.5	(35)	3,747,659	1.83	25,255
369.00	SERVICES	73,021,590.19	65-R4	(125)	1,029,604	1.41	65-R4	(125)	1,322,641	1.81	293,037
370.00	METERS	56,802,201.89	42-R2.5	(30)	1,147,404	2.02	42-R2.5	(30)	1,426,806	2.51	279,402
371.00	METER INSTALLATIONS	2,165,322.14	30-R0.5	(40)	175,391	8.10	30-R0.5	(40)	134,213	6.20	(41,178)
373.10	STREET LIGHTING AND SIGNAL SYSTEMS	31,556,357.13	42-S0.5	(40)	855,177	2.71	44-S0.5	(45)	825,337	2.62	(29,841)
	TOTAL DISTRIBUTION PLANT	**1,305,686,527.20**			**23,265,667**	**1.78**			**27,496,130**	**2.11**	**4,230,463**
	GENERAL PLANT										
389.20	LAND RIGHTS	3,778.48	75-R3	0	50	1.32	75-R3	0	50	1.32	0
390.10	STRUCTURES AND IMPROVEMENTS	27,398,563.95	57-R2	(15)	383,580	1.40	60-R2	(15)	371,343	1.36	(12,237)
391.00	OFFICE FURNITURE AND EQUIPMENT - OFFICE FURNITURE	2,932,525.30	20-SQ	0	85,923	2.93	20-SQ	0	107,892	3.68	21,969
391.15	OFFICE FURNITURE AND EQUIPMENT - OFFICE EQUIPMENT	288,466.27	10-SQ	0	0	-	10-SQ	0	0	-	0
391.20	OFFICE FURNITURE AND EQUIPMENT - PERSONAL COMPUTERS	2,830,756.55	10-SQ	0	274,300	9.69	10-SQ	0	493,016	17.42	218,716
392.00	TRANSPORTATION EQUIPMENT	4,428,477.06	14-L2	20	36,756	0.83	13-L2	20	111,593	2.52	74,837
393.00	STORES EQUIPMENT	162,237.13	20-SQ	0	4,478	2.76	20-SQ	0	1,866	1.15	(2,612)
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	9,248,862.82	20-SQ	0	408,800	4.42	20-SQ	0	425,310	4.60	16,510
395.00	LABORATORY EQUIPMENT	726,981.47	20-SQ	0	16,502	2.27	20-SQ	0	13,456	1.85	(3,046)
396.00	POWER OPERATED EQUIPMENT	844,671.75	20-S0.5	5	1,689	0.20	20-S0.5	5	(2,538)	(0.30)	(4,228)
397.00	COMMUNICATION EQUIPMENT	18,506,167.11	10-SQ	0	1,676,659	9.06	10-SQ	0	973,325	5.26	(703,334)
398.00	MISCELLANEOUS EQUIPMENT	161,085.56	15-SQ	0	7,571	4.70	15-SQ	0	947	0.59	(6,624)
	TOTAL GENERAL PLANT	**67,532,573.45**			**2,896,308**	**4.29**			**2,496,259**	**3.70**	**(400,049)**
	TOTAL DEPRECIABLE PLANT	**1,398,738,031.26**			**29,313,563**	**2.10**			**31,832,063**	**2.28**	**2,518,499**
	NONDEPRECIABLE										
301.00	ORGANIZATION	124,448.78									
360.10	LAND AND LAND RIGHTS - LAND	11,931,025.07									
389.10	LAND AND LAND RIGHTS - LAND	1,382,979.33									
399.10	ASSET RETIREMENT COSTS - GENERAL PLANT	14,235.89									
	TOTAL NONDEPRECIABLE PLANT	**13,452,689.07**									
	TOTAL ELECTRIC PLANT	**1,412,190,720.33**									

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

In the Matter of the Application	*	
Of The Potomac Edison Company	*	
For Adjustments to its Retail	*	Case No. ____
Rates for the Distribution of	*	
Electric Energy	*	

DIRECT TESTIMONY OF

MARK WARNER

VICE PRESIDENT, GABEL ASSOCIATES INC.

Concerning: EV Charging Program

March 22, 2023

TABLE OF CONTENTS

I. INTRODUCTION

Q1. What is your name, business address, and business affiliation?

A1. My name is Mark Warner and my business address is 417 Denison Street, Highland Park, New Jersey, 08904. I am presently employed as a Vice President at Gabel Associates, Inc. ("Gabel Associates"), an energy, environmental, and public utility consulting firm. Gabel Associates specializes in energy consulting with deep experience in energy procurement, project development, energy policy, environmental analysis, in-depth economic analysis, and overall energy markets including generation, regional operators (especially PJM Interconnection, LLC ("PJM")), and utilities. Over the last six years, I have led our firm's development of a specialized practice related to Plug-In Electric Vehicles[1] ("EVs"), especially regarding utility EV programs and the grid impacts of EV charging.

Q2. What is your professional experience and educational background?

A2. At Gabel Associates, I lead a team of analysts that provides specialized economic, financial, environmental, and policy analysis related to energy markets and a variety of clean energy technology applications. I have been leading technical teams for over 35 years across a variety of utility industries, and I have been specializing in energy market policy and analysis since 2001. I have documented expertise in economic modeling and policy development for new clean energy technologies, particularly regarding utility implications and energy market impacts. My primary

[1] Within the scope of this testimony, all references to "EVs" includes the general category of on-road vehicles that have a plug and can be re-charged from any external source of electricity, including pure battery electric vehicles and plug-in hybrids that include a fueled back-up engine to extend range. This does not include traditional hybrids (without a plug) or fuel-cell vehicles.

focus areas include renewable energy, energy storage, microgrids, advanced "behind the meter" energy project development, and EVs. I support a wide variety of public and private clients, including electric utilities, and I interact closely with a variety of government agencies and regulatory authorities. I lead our firm's practice on EV research and policy development, where we have been active for over six years. I am a co-founder of the ChargEVC[2] electric vehicle coalition, which is currently active in New Jersey and Pennsylvania, and I lead the research, analysis, and policy development efforts of that group. I received my education from the Georgia Institute of Technology where I received a B.S. and M.S. in Mechanical Engineering. I was recognized as Clean Energy Market Innovator of the Year by the New Jersey Board of Public Utilities in 2008, and I served on the board of the Mid-Atlantic Solar Industry Association for four years.

Q3. What experience do you have with the electric vehicle market?

A3. The emerging EV market has been my primary focus area for the last six years. I routinely monitor industry developments, support a variety of clients with specialized market research, work with utilities that are developing programs as a subject matter expert, and interact with a wide variety of policy makers in multiple states regarding market development initiatives for EVs. A key focus area has been the development of tools and methodologies for assessing EV impacts on energy markets and electric

[2] ChargEVC is a not-for-profit coalition of diverse stakeholders that support development of the electric vehicle market in New Jersey. Stakeholders include all four New Jersey electric utilities, both local and national environmental groups, New Jersey car retailers, vehicle manufacturers, charging companies, consumer advocates, and others.

utility infrastructure, and rigorous methods for analyzing and documenting potential benefits, costs, and the net-benefits resulting from widespread EV adoption. I have worked with ten different electric utilities in five states on the development of their EV programs, including tasks such as forecasting, opportunity assessment, strategic planning, EV program design, budgeting, regulatory filing support (including preparation of testimony), benefit-cost analysis, and program implementation support. In addition, in support of market development efforts by ChargEVC in New Jersey, I was the lead investigator for a comprehensive benefit-cost study for the State entitled *Electric Vehicles in New Jersey, Costs and Benefits: The Opportunities, Impacts, and Market Barriers to Widespread Vehicle Electrification in New Jersey*.[3] I recently issued an updated version of this study that considered the potential for electrification of the entire on-road transportation market, including medium- and heavy-duty vehicles.[4] This most recent analysis involved a substantial expansion of the data involved in EV analysis[5], and completely revised methodologies for assessing both costs and benefits of widespread EV adoption. Those updated tools and datasets enable a highly specialized analysis of EV impacts on electricity markets and infrastructure, and rigorous determination of benefits, costs, and Benefit-Cost Analysis (BCA) using net-benefit assessments specific to the electric utility EV programs. I am also a

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[3] See http://www.chargevc.org/wp-content/uploads/2018/03/ChargEVC-New-Jersey-Study.pdf.

[4] See http://www.chargevc.org/wp-content/uploads/2020/10/ChargEVC-Full-Market-Electrification-Study-FINAL-Oct-7-2020.pdf

[5] Including details on vehicle specifications, charging technology, consumer adoption and usage behaviors, a wide range of economic and environmental factors, detailed analysis of real-world vehicle charging data, and details related to electricity markets such as energy cost, capacity costs, and time-of-day distributions, data provided by the utilities, information about utility EV programs, and relevant policy documents.

frequent public speaker in a wide variety of forums regarding the EV market, policy development for EVs, and electric utility implications of widespread EV adoption.

Q4. Have you previously appeared before the Maryland Public Service Commission ("Commission") in matters related to plug-in electric vehicles?

A4. Yes. I have been actively supporting multiple electric utilities in the State of Maryland for the last four years, including presenting both studies and testimony to the Commission. I supported Baltimore Gas and Electric ("BGE") during the early stages of their EV program design, and provided opinion letters to the Commission on various EV-related matters. In 2020 I provided testimony on a benefit-cost analysis of EV programs (herein generally referred to as "EV-BCA") as part of BGE's Multi-Year Plan ("MYP") in Case No. 9645. Also in 2020, I supported Potomac Electric Power Company ("PEPCO") and Delmarva Power & Light Company ("DPL") in preparation of BCA analysis for the proposed off-peak/off-bill filings. I provided BCA testimony on EV programs as part of PEPCO's MYP in 2020 in Case No. 9655. I have supported Potomac Edison ("PE" or "Company") in quarterly surveys of the public charging market in Maryland, including detailed pricing studies in support of proposed utility pricing for that company's public chargers. Most recently, I supported the joint utilities (BGE, PEPCO, DPL, PE, and Southern Maryland Electric Cooperative ("SMECO")) in the year-long EV-BCA working group, and I authored the consensus document for the methodology that was approved by the Commission in January 2022[6]. Based on that new approved EV-BCA methodology, I prepared an EV-BCA and written

[6] Commission Letter Order, Case No. 9478 (Jan. 12, 2022), ML238539.

testimony for DPL's MYP in Case No. 9681. That approved methodology, as adapted for PE's program design, is the basis for this testimony.

Q5. What is the purpose of your Direct Testimony?

A5. The purpose of my Direct Testimony is to present the methodology and results of the analysis that I performed regarding the suite of EV charging program offerings developed and implemented by PE, in support of its current rate case. The offerings I analyzed are part of the "EV Driven" program the Company launched in year 2019.

Q6. Have you completed analysis of PE's EV programs based specifically on the methodology the EV-BCA working group proposed and the Commission adopted?

A6. Yes. Based on the EV-BCA Methodology developed by the EV-BCA working group, as approved and adopted by the Commission, I developed assessments of cost effectiveness and ratepayer impact.[7] Within this Testimony, I will refer to that methodology as the "MD EV-BCA Methodology".

Q7. What are the assessments used in the MD-EV-BCA Methodology?

A7. As summarized in the Electric Vehicle Benefit/Cost Analysis Methodology by the Maryland Joint-Utilities ("EV BCA Whitepaper"), and defined in Section 3 of that document, the Commission approved five separate assessments for evaluation of electric utility EV programs:

1. **Primary Test - MD EV-JST:** Quantifies the cost effectiveness of electric utility EV programs resulting from impacts on the utility system, host customers (i.e.,

[7] ELECTRIC VEHICLE BENEFIT/COST ANALYSIS METHODOLOGY BY THE MARYLAND JOINT-UTILITIES (FINAL DRAFT), Mark Warner, November 30, 2021.

participants), and society, consistent with Maryland policy goals (i.e., a Jurisdiction Specific Test, or JST).

2. **Market-Wide Test - MW:** The same methodology as the MD EV-JST, but applied market-wide[8] to quantify the net benefits of vehicle electrification overall when considered on a societal basis. Three sensitivities will be considered: all natural charging, all managed charging, and an intermediate "likely case" as expected results from currently approved utility filings. Natural charging reflects scenarios where customers charge EVs as per their usual practice (typically when returning home from work), without incentives that encourage charging during off-peak times. Managed charging refers to modified customer behaviors in response to off-peak charging incentives, which can take a variety of forms (including Time-Of-Use ("TOU") rate designs and off-bill rebates). The "100% natural" and "100% managed" represent opposite boundary conditions, with real-world results likely to be somewhere between these two extremes.

3. **ANRI (all):** Aggregate non-participating-ratepayer impact ("ANRI") as induced by the electric utility program, including both monetized impacts (on utility bills) and important externalities (such as environmental benefits and improved public health). This assessment is provided for both each electric utility EV-programs individually and for the entire portfolio of programs.

[8] "Market-Wide", in this context, refers to ALL the EVs in the EV territory, not just the customers participating in EV-related utility programs. As explained in the MD EV-BCA Methodology, this assessment quantifies the net benefit (within a JST context) of vehicle electrification overall.

4. **ANRI (bills-only):** A sensitivity of the ANRI calculation that considers only monetized impact on utility bills (i.e., does not include environmental or public health benefits). Both individual-program and portfolio-level variations have been developed.
5. **Other Strategic Considerations:** An inventory of other qualitative factors that provide important context for the quantified assessments.

Q8. Can you provide an executive summary of the BCA and the associated results?

A8. Yes. I implemented all the assessments specified in the MD EV-BCA Methodology approved by the Commission. The electric utility implemented these programs as pilot projects approved by the Commission to help jump-start charging infrastructure development, and to provide learning on which programs are most effective.

- The best aggregate measure of program cost effectiveness is the outcome for the MD EV-JST for the overall portfolio, and that outcome was above 1.0, indicating that the Net Present Value ("NPV") of benefits exceeded costs.
- Both the public L2 and public DCFC also has MD EV-JST results above 1.0, indicating that those individual programs are cost effective on a stand-alone basis. The outcomes for the two residential programs were both below the 1.0 threshold, but likely reflect the very small scale of the pilot programs.
- For the market-wide assessment, the benefit/cost ratios were greater than 1.0 in all three scenarios considered (100% natural residential charging, 100% managed residential charging, and for the degree of residential managed charging currently

approved and being deployed by PE). The managed-charging case had a slightly stronger outcome, reflecting the benefit of avoiding the costs associated with charging during peak time. The "Approved" variation of the Market-Wide JST was essentially identical to the "Natural" case, since a relatively small fraction of the full market has been approved for participation in the managed charging programs.

- The ANRI assessments of net ratepayer impact demonstrate mixed results: for the "all" case where externalities (e.g. reduced emissions) are included, ratepayers are better off (i.e. lower net costs) for the portfolio overall, and for the L2 and DCFC public offerings. Both the residential programs had costs that exceeded benefits. For the "bills-only" case where externalities are not considered, ratepayer costs exceed benefits for all programs. This result is not unexpected, since the "bills-only" case excludes externalities (such as lower emissions) that are a primary strategic motivation for these programs.

The result sections below summarize all these results in more detail.

II. ASSESSMENT APPROACH AND METHODOLOGY

Q9. How did you complete the analysis of the PE EV programs?

A9. The analysis depended on three phases of work: a) working with PE to identify the exact offerings that would be assessed, and collecting the program data required as inputs to the EV-BCA model, b) developing the assessment model as guided by the Maryland EV-BCA Methodology, including research and analysis on additional inputs needed for the computation, and c) computing assessment results. This section of the testimony summarizes the details of those three phases of work.

Q10. Which PE "EV Driven" offerings were included in the analysis?

A10. I worked with PE to identify an appropriate portfolio of "EV Driven" offerings for inclusion in the analysis. I performed this study during the latter half of the currently approved lifecycle for PE's "EV Driven" program, and real-world data on program costs and customer vehicle charging behaviors is now available. In selecting program offerings appropriate for this analysis, I focused on those offerings for which sufficient data are available for a meaningful analysis per the Maryland EV-BCA Methodology. In addition, when identifying the base of offerings to be assessed, I also considered the fact that some of these programs are used together by customers in the "EV Driven" program. Based on those factors, the analysis is based on four separate offerings, which can also be combined to provide a portfolio-view:

1. **Off-Peak/Off-Bill Incentive (OPOB-Only):** This off-bill incentive is structured as a $0.02 payment for each kilowatt-hour ("kWh") of off-peak charging, net of any on-peak charging[9]. On-Peak for this incentive offering is defined as 6:00 AM to 11:00 PM, Monday-Friday, except for holidays. The incentive is paid directly to the customer (via an off-bill payment) and provides a recurring tangible feedback to the customer about the benefits of off-peak charging.
2. **Charger Rebate and Off-Peak/Off-Bill:** This offering combines the $300 rebate for customers that install a utility-approved smart charger with opt-in use of an

[9] As an example, if over a given period the customer has 100 kWhs of charging during off-peak times, but 40 additional kWhs during on-peak times, the 2 cents/kWh incentive it paid was 60 kWhs (100-40).

incentive that encourages off-peak charging. The off-bill incentive is structured as a $0.02 payment for each kWh of off-peak charging, net of any on-peak charging, as described in the offering above.

3. **Public L2 Chargers:** Under this offering the electric utility develops, owns, and operates L2 chargers for public use, with the goal of reducing range anxiety concerns and increasing EV adoption. As defined in the Maryland EV-BCA Methodology, assessment of this offering is based on the degree of increased adoption resulting from the improved availability of public L2 chargers and the full scope of costs and benefits associated with that stimulated adoption.
4. **Public Direct-Current Fast Chargers ("DCFC"):** Under this offering the electric utility develops, owns, and operates high-powered fast chargers for public use, with the goal of reducing range anxiety concerns and increasing EV adoption. These chargers can be particularly impactful on EV market development, since many mainstream consumers value the speed and convenience these chargers offer. As defined in the Maryland EV-BCA Methodology, assessment of this program is based on degree of increased adoption resulting from the increased availability of public DCFC chargers, and the full scope of costs and benefits associated with that stimulated adoption.
5. BCA was not performed for the multi-family offers since sufficient charging data was not yet available.

Q11. How did you develop the quantitative model used in the analysis?

A11. I applied the framework developed by the EV-BCA working group during 2021, as approved by the Commission in January 2022. My guiding principles for development of that model were to strictly apply the principles and details defined in the Maryland EV-BCA Methodology, while adapting the generally defined assessments in that methodology to the details of the "EV Driven" program. Key inputs were aligned with similar inputs used by the EmPOWER program (where possible). The offerings defined above align directly with the "generic offers" outlined in the Maryland EV-BCA Methodology, and therefore its portfolio of impact factors could be applied in a straight-forward way.

Q12. What impacts did you consider in performing the assessments?

A12. I analyzed both cost effectiveness and ratepayer impacts, and also identified a variety of strategic factors that are relevant to program assessment, as defined in the MD EV-BCA. These calculations depend on quantification of impacts to the electric utility, to society as a whole, to the EV owner/operators (program participants), and PE ratepayers. Please refer to Section 4 of the MD EV-BCA Methodology whitepaper for details on the impact factors used in my analysis. I used all of the impacts defined in the whitepaper for each assessment.

How these generic impacts apply to a particular offering varies depending on the details of the offering design, the assessment being performed, and how a given program is expected to impact the market (e.g., changing consumer charging behavior or increasing EV adoption). Those variations are addressed through offering-specific templates that clarify impact interpretation for each assessment/offering combination, as outlined in more detail below. These templates are outlined specifically in the Maryland EV-BCA Methodology, and were the authoritative reference for design of the assessments used in this testimony.

Q13. How do these impact factors relate to the assessments being performed?

A13. For the societal-scope assessments (the MD EV-JST and Market-Wide), these impact factors are quantified (NPV dollars) as either costs or benefits. For the ANRI ratepayer impact assessments, each factor either increases or decreases ratepayer impact, the net sum of which (on an NPV basis) provide the aggregate outcome. The generic mapping of these impacts to each of those four assessments is summarized in Figure 1 below:

Figure 1: Quantitative Assessment Framework

(from Figure 5.1 – 1 in MD EV-BCA Whitepaper)

Impact-Factor	MD EV-JST	MW-Test	ANRI (All)	ANRI (Bills Only)
Utility (and Power Sector) Impacts				
Utility Program Administration Costs	Cost	Cost	Increase	Increase
Utility Program Implementation Costs	Cost	Cost	Increase	Increase
Impacts On Capacity Costs	Cost or Benefit	Cost or Benefit	Increase or Decrease	Increase or Decrease
Impacts On Transmission Costs	Cost or Benefit	Cost or Benefit	Increase or Decrease	Increase or Decrease
Wholesale Energy Cost Impacts	Cost or Benefit	Cost or Benefit	Increase or Decrease	Increase or Decrease
Increased Electricity (KWHr) Costs (for EV charging)	Cost	Cost	Increase	Increase
Impacts on Grid Reinforcement	Cost or Benefit	Cost or Benefit	Increase or Decrease	Increase or Decrease
Utility-Owned EV Chargers - Costs	Cost	Cost	Increase	Increase
Utility-Owned EV Chargers - Usage $ From EV Drivers	Transfer	Transfer	Decrease	Decrease
Increased RPS Compliance Costs	Cost	Cost	Increase	Increase
T&D Losses	Cost or Benefit	Cost or Benefit	Increase or Decrease	Increase or Decrease
Utility Equipment Incentives	Transfer	Transfer	Increase	Increase
Utility Rate Incentives	Transfer	Transfer	Increase	Increase
Increased Utility Revenues	Transfer	Transfer	Decrease	Decrease
Participant Impacts(from EV Driver Perspective)				
Incremental EV Purchase Costs	Cost	Cost	N/A	N/A
EV Charger Costs (equipment and installation)	Cost	Cost	N/A	N/A
Avoided Vehicle Fuel Costs	Benefit	Benefit	N/A	N/A
Savings From Decreased Vehicle Maintenance	Benefit	Benefit	N/A	N/A
Federal Tax Incentive (EV purchase)	Benefit	Benefit	N/A	N/A
Societal Costs or Benefits (from Society's Perspective)				
Value Of Reduced GHG Emissions	Benefit	Benefit	Decrease	N/A
Public Health Value Of Reduced/Shifted Emissions	Benefit	Benefit	Decrease	N/A

The first two tests (MD EV-JST and MW-Test) represent classic benefit/cost ratios (of NPVs) at "societal scale" from two different perspectives: the MD EV-JST considers just the fraction of the EV market directly impacted by the utility EV programs, while the MW-Test quantifies a similar benefit/cost ratio for the entire number of EVs on the road. The factors included in these tests vary by utility EV offering, since each offering impacts the market differently, as noted in Figure 2.

Figure 2: Factors Considered In Societal-Scale Assessments

(from Figure 5.3 – 1 in Maryland EV-BCA Whitepaper)

Impact-Factor	MD EV-JST (UO-1): Residential Managed Charging	MD EV-JST (UO-2): Multi-Family Charging	MD EV-JST (UO-3): Utility Owned Public Chargers	Market-Wide Test
Computation Scope:	Induced Charging Behavior	Induced Adoption	Induced Adoption	All EVs On The Road
Baseline:	EV Owner, Nat-Chrging	No EV Adoption	Pull-Through Adoption	Depends on Scenario
Utility (and Power Sector) Impacts				
Utility Program Administration Costs	Cost	Cost	Cost	Cost
Utility Program Implementation Costs	Cost	Cost	Cost	Cost
Impacts On Capacity Costs	Benefit	Cost	Cost	Cost or Benefit
Impacts On Transmission Costs	Benefit	Cost	Cost	Cost or Benefit
Wholesale Energy Cost Impacts	Benefit	Cost or Benefit	Cost or Benefit	Cost or Benefit
Increased Electricity (KWHr) Costs (for EV charging)	N/A	Cost	Cost	Cost
Impacts on Grid Reinforcement	Benefit	Cost	Cost	Cost
Utility-Owned EV Chargers - Costs	N/A	N/A	Cost	Cost
Utility-Owned EV Chargers - Usage $ From EV Drivers	N/A	N/A	Transfer	Transfer
Increased RPS Compliance Costs	N/A	Cost	Cost	Cost
T&D Losses	Benefit	Cost	Cost	Cost
Utility Equipment Incentives	Transfer	Transfer	Transfer	Transfer
Utility Rate Incentives	Transfer	Transfer	Transfer	Transfer
Increased Utility Revenues	Transfer	Transfer	Transfer	Transfer
Participant Impacts(from EV Driver Perspective)				
Incremental EV Purchase Costs	N/A	Cost	Cost	Cost
EV Charger Costs (equipment and installation)	N/A	Cost	Cost	Cost
Avoided Vehicle Fuel Costs	N/A	Benefit	Benefit	Benefit
Savings From Decreased Vehicle Maintenance	N/A	Benefit	Benefit	Benefit
Federal Tax Incentive (EV purchase)	N/A	Benefit	Benefit	Benefit
Societal Costs or Benefits (from Society's Perspective)				
Value Of Reduced GHG Emissions	N/A	Benefit	Benefit	Benefit
Public Health Value Of Reduced/Shifted Emissions	N/A	Benefit	Benefit	Benefit

The two ANRI assessments are based on a NPV of impacts for non-participating ratepayers (i.e., those ratepayers who bear some cost for the utility EV offering, but who are not participating directly in that offering). The ANRI-all assessment considers the case where all ratepayer impacts are considered (including externalities such as reduced Carbon Dioxide (“CO2”) emissions and impacts on public health), and also considering direct impacts on customer utility bills only. The ANRI-bills-only considers the case where only impacts that are monetized onto the electric utility bill are included. Figure 3 summarizes the factors for the two ANRI ratepayer impact assessments.

Figure 3: Factors Considered In ANRI Assessments

(from Figure 5.4 – 1 in the EV-BCA Whitepaper)

Impact-Factor	UO-1: Residential Managed Charging	UO-2: Multi-Family Charging	UO-3: Utility Owned Public Chargers
Computation Scope:	Induced Charging Behavior	Induced Adoption	Induced Adoption
Baseline:	EV Owner, Nat-Chrging	No EV Adoption	Pull-Through Adoption
Utility (and Power Sector) Impacts			
Utility Program Administration Costs	Increase	Increase	Increase
Utility Program Implementation Costs	Increase	Increase	Increase
Impacts On Capacity Costs	Decrease	Increase	Increase
Impacts On Transmission Costs	Decrease	Increase	Increase
Wholesale Energy Cost Impacts	Decrease	Increase or Decrease	Increase or Decrease
Increased Electricity (KWHr) Costs (for EV charging)	Increase	Increase	Increase
Impacts on Grid Reinforcement	Decrease	Increase	Increase
Utility-Owned EV Chargers - Costs	N/A	N/A	Increase
Utility-Owned EV Chargers - Usage $ From EV Drivers	N/A	N/A	Decrease
Increased RPS Compliance Costs	Increase	Increase	Increase
T&D Losses	Decrease	Increase	Increase
Utility Equipment Incentives	Increase	Increase	Increase
Utility Rate Incentives	Increase	Increase	Increase
Increased Utility Revenues	Decrease	Decrease	Decrease
Participant Impacts(from EV Driver Perspective)			
Incremental EV Purchase Costs	N/A	N/A	N/A
EV Charger Costs (equipment and installation)	N/A	N/A	N/A
Avoided Vehicle Fuel Costs	N/A	N/A	N/A
Savings From Decreased Vehicle Maintenance	N/A	N/A	N/A
Federal Tax Incentive (EV purchase)	N/A	N/A	N/A
Societal Costs or Benefits (from Society's Perspective)			
Value Of Reduced GHG Emissions	N/A	"All" Case Only	"All" Case Only
Public Health Value Of Reduced/Shifted Emissions	N/A	"All" Case Only	"All" Case Only

Q14. Are there qualitative factors identified as a result of your analysis?

A14. Yes. The Maryland EV-BCA Methodology includes a fifth assessment that allows for the consolidation of strategic factors that are relevant to interpretation of the other quantified results. I created an inventory of these factors as they were identified during the data collection and analysis process, in consultation with PE. They are summarized in the results sections below.

Q15. What sources of information were provided as inputs to the analysis?

A15. Consistent with the guidelines established in the MD EV-BCA Methodology, the analysis depends on inputs that represent assumptions, boundary conditions, data about program costs and real-world impacts, and selection of key sources for other necessary inputs. Since this analysis is being completed as part of the PE rate case, I included input factors consistent with other analyses the Company performed as part of that rate case. A summary of key input factors is provided below:

a) **Utility Program Design Details:** I worked with PE to inventory key design parameters for each of the offerings described above, including details such as customer eligibility criteria, tariff linkages, time-of-day boundaries (for off-peak incentives), incentive levels, and approved program sizing.

b) **Projected Utility Program Deployment Rates:** Since all assessments are based on NPVs, it is necessary to consider how costs and benefits are realized over time. I worked with PE to establish a projection of expected deployment over time, which equates roughly to "customer sign-ups" each year of the program.

c) **Planned Utility Program Costs:** As defined in the Maryland EV-BCA Methodology, it is necessary to account for administrative costs (including operations costs like charging network fees and implementation contractor costs)[10], implementation costs (during program start-up), and the costs for construction, maintenance, and long-term operation of utility-owned public chargers. Due to unpredicted supply chain issues over the last few years, PE pre-bought a lot of equipment in advance, incurring costs before benefits were realized. This was done

[10] "Costs" as defined in the MD EV-BCA Methodology are not equivalent to "budgets" as managed internally by the electric utility.

to ensure materials were in stock when jobs were ready, a necessary operations decision post-COVID. However, this necessity may have negatively impacted the BCA outcomes. Note that most of these costs are budgeted as part of the program, and terminate at the approved program sunset. In some cases, costs may continue past program sunset, such as the costs of operating public charging over the full period during which benefits are realized. Therefore, the electric utility program cost plan accounts for formally budgeted costs within approved program boundaries, as well as longer term costs where necessary.

d) **Customer Charging Behaviors:** One of the most important data sets associated with the assessment is an understanding of exactly how and when customers charge their EVs. Statistics such as usage frequency, average kWhs dispensed per charging transaction, and the extent of charging coincidence with peak periods have a direct impact on the assessment computation. These statistics were based on an in-depth analysis of charging data collected from the smart chargers installed by EV owners under the residential smart charging rebate program, and/or data collected directly from utility-owned chargers.[11] Within the residential charging segment, two sub-groups were defined: a) those customers that use a smart charger but are *not* on an off-peak incentive program (like OPOB), and b) those customers with a smart charger that *are* on an off-peak incentive program. The first group

[11] The location where public chargers are deployed have a significant impact on BCA outcome, since different sites could experience different traffic patterns and therefore different time-of-day profiles. Two physically identical installations, with all other details being equivalent but with different charging profiles could result in different BCA outcomes. Customer behavior is therefore a significant part of the BCA result.

represents the control group for "natural charging"[12], while the second group represents the charging behavior of the "managed charging" segment. This managed charging segment is evaluated as part of the assessment. A variety of other vehicle-specific statistics, such as vehicle efficiency (miles/kWh or miles/gallon), and emission factors (or traditional non-electric vehicles), were developed based on research of market sources.

e) **Induced Adoption Factors:** The public charging programs are motivated by the need to increase the number of public chargers active in the market, and to thereby reduce consumer concerns about range anxiety to encourage and increase EV adoption. As specified in the Maryland EV-BCA Methodology, the assessment is based on the impacts from that induced vehicle adoption. I considered multiple sources of information to develop a conservative set of factors that translate the number of utility-owned chargers deployed to the associated induced adoption.

f) **Service Life:** As with other BCA computations (in the energy efficiency market, for example), benefit/cost calculations are performed over a multi-year period based on the length of the service life of the investment. The residential smart charging programs are assumed to induce changed charging behavior over an eight-year period due to the customer charging-habit established during the incentive period. For utility-owned chargers (both L2 and DCFC), service life is assumed to be 15 years to align with the depreciation period established by the Commission for

[12] Assessment of this "control group" were not completed as part of this analysis, since the "control group" cannot be compared to itself.

these assets. These factors are consistent with my understanding of industry practices and expectations.

g) **Economic Factors:** A wide variety of economic factors are needed to combine the data outlined above into an impact computation as needed for each assessment. These factors came from both PE and research I (or my team) completed as part of this project. Key economic factors include:

   a. **Inflation Factor:** Provided by PE to be consistent with EmPOWER assumptions.

   b. **NPV Discount Rate:** Set at 2.0%, consistent with the discount rate used in the computation of the Social Cost of Carbon ("SCOC"), as specified in the MD EV-BCA Methodology.

   c. **Tariffed Rates:** Detailed rates for residential, small-commercial, and the rates charged to EV-Drivers (Schedule EVP Tariff), including historical for 2019- 2022, and a forward projection of rates based on the inflation factor. PE provided all listed tariffed rates.

   d. **Energy and Power Cost Factors:** A variety of factors, including those mostly related to the PJM market, are relevant to the impact calculations. Primary examples include capacity costs, transmission and distribution costs, the period of typical PJM-specific coincident peak for PE, DRIPE[13] for both energy (MWhs) and demand (MWs), and wholesale energy costs (marginal $/MWh). All these factors were based on information provided

[13] DRIPE = "Demand Response Induced Pricing Effect", which quantifies the impact that changes in aggregate load profile will have on wholesale pricing.

by PE to be consistent with assumptions used in EmPOWER MD program analysis. PJM capacity reserve factors were also used based on data provided by PJM. Loss factors were also provided by PE for its territory.

e. **Generation Emissions:** Emission factors (pounds per MWh[14]) for electricity, based on current real-world emissions from eGrid, as projected forward by changing supply mix details in the Maryland Department of Energy 2030 plan. CO_2, NO_X, SO_2, and $PM_{2.5}$[15] were considered for all assessments.[16]

f. **Mobile Emissions:** The emissions from traditional internal combustion engine vehicles based on standardized pound/gallon emission factors from the EPA combined with published national mile-per-gallon efficiency factors.

g. **Value Of Reduced Emissions:** For each ton of reduced emissions, it is possible to compute the associated economic impact (in dollars) using standardized factors. For CO_2, a recent New York State study provided "Social Cost of Carbon" \$-impact factors, based on a 2% discount.[17] Similar factors for NOx, SO_2, and $PM_{2.5}$ were referenced from a recent

[14] MWh = Megawatt-Hour, = 1000 kWh.

[15] CO_2 = Carbon Dioxide, NO_x = the family of Nitrous Oxides, SO_2 = Sulfur Dioxide, PM2.5 = Particulate Matter sized 2.5 Microns or smaller.

[16] The BCA model computes the net change in emissions-mass for all four emissions identified. Net changes for SO2 and PM2.5 were found to be negligible for projections focused on gasoline light-duty vehicles. The analysis therefore attributed CO2 impacts to the "GHG Impact" and NOx to "Public Health Impact" elements of the MD EV-BCA Methodology.

[17] "Establishing a Value for Carbon, Guidelines for Use by State Agencies", New York Department of Environmental Conservation, May 2022, \$-impact factors found in the Appendix.

National Highway Transportation Safety Administration Study ("NHTSA") on those emissions.[18]

h. **Fuel Costs:** Projections of gasoline costs (for use in traditional non-EV vehicles) taken from the federal Department of Energy ("DOE") 2022 Annual Energy Outlook ((https://www.eia.gov/outlooks/aeo/).

i. **Incremental Costs Of EVs:** Taken from a National Renewable Energy Laboratory ("NREL") projection of vehicle costs.[19]

j. **Maintenance Savings:** Taken from an annually published American Automobile Association ("AAA") study on maintenance costs for different vehicle types (2021 Edition).

k. **Federal Tax Credits:** A projection of average federal tax credits used in the EV market based on a changing mix of brands over time, and which accounts for changing eligibility over time. These projections have been updated to reflect changes in the tax credit program through the recently passed "Inflation Reduction Act" legislation.

l. **Charging Equipment Costs:** Taken from an analysis of real charging costs (equipment and installation) collected through the PE EV programs.

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[18] National Highway Transportation Safety Administration, "Technical Support Document: Final Rulemaking for Model Years 2024-2026 Light-Duty Vehicle Corporate Average Fuel Economy Standards, March 2022, Tables 6-22 and 6-23.

[19] These numbers are from NREL's 2017 Electrification Report, Figure 4, for the Rapid Advancement Case.

III. ASSESSMENT RESULTS

Q16. Please summarize your analysis results.

A16. I used the Maryland EV-BCA Methodology to assess four of PE's EV offerings, and a portfolio view considering all offerings taken together. My results are consistent with the multiple assessments specified in the Maryland EV-BCA Methodology to provide several perspectives on the net-impact of those programs. Figure 4 summarizes the outcomes associated with each of the four quantified assessments.[20]

Figure 4: Potomac Edison EV-Program Assessments

CURRENT MODEL RESULTS				
Overall Results Summary	(>1.0 Beneficial)	(>1.0 Beneficial)	Negative Number = Lower Impact	
	Primary JST	**Market-Wide**	**ANRI (All)**	**ANRI (Bill Only)**
Portfolio	**1.03**		**-$6,589,261**	**$3,277,059**
(ANRI Allocation, impact PER Monthly BILL):	**N/A**		**-$0.153109**	**$0.076146**
OPOB-Only	**0.77**		**$27,864**	
(ANRI Allocation, impact PER Monthly BILL):	**N/A**		**$0.001214**	
Charger & OPOB	**0.12**		**$356,990**	
(ANRI Allocation, impact PER Monthly BILL):	**N/A**		**$0.015553**	
Public L2	**1.07**		**-$2,432,673**	**$1,960,003**
(ANRI Allocation, impact PER Monthly BILL):	**N/A**		**-$0.056526**	**$0.045543**
Public DCFC	**1.01**		**-$4,541,443**	**$932,202**
(ANRI Allocation, impact PER Monthly BILL):	**N/A**		**-$0.105526**	**$0.021661**
Market-Wide JST (100% Natural)	**N/A**	**2.33**		
Market-Wide JST (100% Managed)	**N/A**	**2.40**		
Market-Wide JST (Currently Approved Programs)	**N/A**	**2.33**		

Note that the first two assessments (MD EV-JST and the Market-Wide test) are classic benefit/cost ratios, in which a ratio greater than one indicates positive net benefit. The third and fourth ANRI assessments are not benefit/cost ratios, but instead

[20] The Maryland EV-BCA Methodology also allows for identification of qualitative factors relevant to consideration of the results. This chart summarizes the result of the quantitative assessments, and the inventory of qualitative strategic details are summarized separately in the testimony.

represent net present values of ratepayer impacts, where a positive number indicates an increase in impacts to ratepayers (a non-beneficial outcome), and a negative number indicates a decrease in impacts on ratepayers (a beneficial outcome).

As highlighted in the MD EV-BCA Methodology, the primary assessment is the Jurisdiction Specific Test (MD EV-JST), which is a social-scope assessment tuned specifically to Maryland policy conditions.

- For the primary MD EV-JST test, the overall portfolio had an outcome above 1.0, indicating that the NPV of benefits exceeded costs.
- Both the Public L2 and Public DCFC offers are also deemed cost-effective based on MD EV-JST outcomes above 1.0.
- The two residential offers both had MD EV-JST outcomes below 1.0, which likely reflects the very small scale of the pilot programs, as further detailed below. Of the two, the OPOB-Only offer is the strongest, since it doesn't bear the additional administrative costs associated with the charger rebate.
- The Market-Wide test quantifies whether vehicle electrification is beneficial overall, considering all vehicles in the market, not just those directly impacted by the approved utility programs. Three scenarios are defined in the MD EV-BCA Methodology: a) 100% of residential customers are on managed charging, b) 0% of residential customers use managed charging (i.e. natural charging only), and c) an intermediate case where managed charging is limited to the scope of utility programs already approved. There is net-benefit for the Market-Wide assessment

in all three cases, with the benefit/cost ratio being slightly higher in the 100% managed charging case.

- The ANRI-all test yields favorable results (i.e. net ratepayer impacts go down) for the portfolio overall, and for the Public L2 and Public DCFC offers. The two residential programs demonstrated unfavorable results for the two residential programs. I consider this assessment to be the most relevant assessment of direct ratepayer impact, since utility EV programs are intended to lower emissions through EV adoption and optimal use, and this test reflects both environmental impacts (which are not monetized) and direct economic impacts (on utility bills) when taken together.
- The ANRI-bills-only test considers only the monetized impacts that show up on a customer's utility bill, and the unfavorable outcome (i.e. a number > 0) associated with that assessment means that ratepayer costs will increase slightly.
- As specified in the methodology, the ANRI result is divided by the number of residential customers over a specified period of time to arrive at an absolute dollar-impact per residential bill. It is important to emphasize that these ANRI impacts allocated to residential bills is an illustrative metric only, intended to provide context for the ANRI outcome.

In addition to providing absolute assessments of each offer (and the portfolio), these results can be used to understand relative cost-effectiveness and ratepayer impacts across programs. The electric utility implemented these programs as required by the Commission, and given the real-world results that have now been measured, these outcomes can help identify the relative merit of different offer designs. As further detailed below, some care is required when interpreting the absolute results since the Pilot programs are of fairly small scale, which likely had an impact on BCA outcomes. The following sections provides results on a per assessment method (across all offerings), as well as on an offering-by-offering basis (across all assessments).

Q17. What is the assessment outcome for the Primary Test (MD EV-JST)?

A17. The Maryland EV-BCA Methodology defines a single primary test that is intended to be the principal basis for determining cost-effectiveness of electric utility EV programs. This assessment is similar to a traditional "societal cost test," and covers a broad range of both costs and benefits associated with either EV adoption, or the shifting of charging behavior to off-peak time (depending on the offering considered). Figure 5 summarizes the results of the MD EV-JST for each offering and the portfolio of offerings.

Figure 5: MD EV-JST Results

Results Summary: MD EV-JST	(>1.0 Beneficial) Primary JST
Portfolio	1.03
OPOB-Only	0.77
Charger & OPOB	0.12
Public L2	1.07
Public DCFC	1.01

The portfolio overall, and both public charging programs, have outcomes above 1.0, which implies cost-effectiveness. The two residential programs (OPOB-only, and

OPOB when combined with a charger rebate) demonstrate unfavorable outcomes less than 1.0.

The Maryland EV-BCA Methodology puts programs on an equivalent assessment basis so that programs can be compared with each other, although that is best done within program types. In this case, the OPOB-only offer is significantly more beneficial than the Charger & OPOB offer, since it avoids certain administrative costs. **It is worth noting that these simple BCA-outcomes can mask the absolute numbers involved – especially since these pilot programs are of very small scale. In the case of the OPOB-only program, for example, reducing administrative costs by only $18,000 over a multi-year period would have resulted in a favorable outcome (>1.0). These outcomes should therefore be considered within the small scale of these initial pilot offerings, and the results are best used to consider the cost-effectiveness of pilot offerings relative to each other.**

Q18. What is the outcome for the Market-Wide Assessment?

A18. The NPV of benefits exceeds the NPV of costs for all three scenarios of the Market-Wide case, demonstrating that society overall is better off as a result of widespread vehicle electrification. This assessment does not measure cost-effectiveness of specific electric utility offerings, although the currently approved electric utility offerings were included in the inventory of costs. As summarized in Figure 6 below, the net benefits were higher in the case where residential managed charging becomes dominant as a result of avoided capacity, transmission, and distribution costs. The average of the two OPOB programs (with and without the charger rebate) was used as the reference point for residential managed charging, scaled up to full market participation in the 100% managed charging case.

Figure 6: Market-Wide Test Results

Results Summary: Market-Wide Test	(>1.0 Beneficial) Primary JST
Market-Wide (100% Natural Residential Charging)	2.33
Market-Wide (100% Managed Residential Charging)	2.40
Market-Wide (Approved Managed Charging)	2.33

Q19. In the case where all ratepayer impacts are considered, what is the outcome for ANRI-all assessment?

A19. The MD EV-BCA ANRI-all assessment evaluates the impact on ratepayers when all impacts are considered, including changes in utility costs (or avoided costs) and the impact of externalities, such as reduced emissions. Consideration of those reduced emissions is meaningful since that is a primary motivation for many of the electric utility "EV Driven" offerings. The scope of this assessment is exclusively non-participating ratepayers, and specifically addresses the policy question about how rate payers who do not participate directly in a given program (i.e., EV owner/operators) are impacted. As emphasized in the Maryland EV-BCA Methodology, the ANRI assessment is not a measure of utility program cost-effectiveness. Instead, it quantifies an estimate of aggregate impact on utility ratepayers through a net-NPV assessment of factors that increase utility costs, compared with factors that decrease utility costs. Therefore, the ANRI outcome is not a ratio like the societal-scale tests summarized above; it is an absolute measure of net dollar-impact, in which a negative number means ratepayer impacts go down (i.e., are beneficial). Figure 7 summarizes the results of the ANRI-all assessment.

Figure 7: ANRI – All Impacts

Results Summary: ANRI (ALL)	Negative = Better ANRI (All)
Portfolio	**-$6,589,261**
(ANRI Allocation, impact PER BILL):	**-$0.153109**
OPOB Only	**$27,864**
(ANRI Allocation, impact PER BILL):	**$0.001214**
Charger & OPOB	**$356,990**
(ANRI Allocation, impact PER BILL):	**$0.015553**
Public L2	**-$2,432,673**
(ANRI Allocation, impact PER BILL):	**-$0.056526**
Public DCFC	**-$4,541,443**
(ANRI Allocation, impact PER BILL):	**-$0.105526**

The ANRI-All outcome for the portfolio overall is favorable (i.e. an outcome < 0), and also a favorable outcome for both the Public L2 and Public DCFC offers. The outcomes for the two residential programs are unfavorable, although for Public-L2 the absolute magnitude of that outcome is relatively small.

Q20. Can you provide ratepayer context for those ANRI outcomes?

A20. Yes. The Maryland EV-BCA specifies that in addition to the NPV outcome, each ANRI-all result is translated to a "per residential customer monthly bill" impact, which is the ANRI result, divided by the average number of residential customers and the number of monthly bills received by those customers during the period over which benefits are realized. These results are therefore an average dollar-change, either up or down, per monthly residential bill. This allocation of ANRI results is only illustrative, to provide context (as specified in the MD EV-BCA Methodology) for the primary ANRI outcome. It is a comparison metric only, and inherently assumes (to provide a standardized benchmark) the quantified impacts apply only to residential customers. In the case of the ANRI-all assessment, this is a hypothetical scenario that contemplates externalized impacts (such as air emissions) were monetized to the ratepayer, in addition to impacts on the electric utility bill. It is a useful perspective on ratepayer impact, but does not represent a real-world cash flow.

As noted in Figure 7, both the portfolio and both public charging programs demonstrate favorable ANRI-all impact (i.e. ratepayer costs go down), however the two residential programs demonstrate an unfavorable impact (i.e. ratepayer costs go up).

Q21. In the case where only utility-bill impacts are considered, what is the ANRI-Bills-Only result?

A21. The ANRI-bills-only case quantifies ratepayer impact in the case where only monetized impacts on the utility bill are considered. As with the ANRI-all assessment, the scope is aggregate impact on non-participating ratepayers. Figure 8 summarizes the results of the ANRI-bills-only assessment:

Figure 8: ANRI – Bill Impacts Only

Results Summary: ANRI (Bill Only)	Negative = Better ANRI (Bill Only)
Portfolio	**$3,277,059**
(ANRI Allocation, impact PER BILL):	**$0.076146**
OPOB-Only	**$27,864**
(ANRI Allocation, impact PER BILL):	**$0.001214**
Charger & OPOB	**$356,990**
(ANRI Allocation, impact PER BILL):	**$0.015553**
Public L2	**$1,960,003**
(ANRI Allocation, impact PER BILL):	**$0.045543**
Public DCFC	**$932,202**
(ANRI Allocation, impact PER BILL):	**$0.021661**

This test yields unfavorable outcomes (impacts > 0) for all four programs and the portfolio, which implies that utility costs to non-participating ratepayers go up for the ANRI-bill-only case. It is important to emphasize that the ANRI-bill-only case excludes externalities (such as CO2 reductions or improvements in public health) that are the strategic motivation for key programs. In all cases, however, the absolute impact is modest, measured in pennies per residential bill.

Q22. Please summarize the assessment results for the full portfolio of offerings taken together.

A22. Figure 9 summarizes the results of each assessment for the portfolio of offerings.

Figure 9: Summary Of All Assessments For The Portfolio Of Offerings

Results Summary: Portfolio	(>1.0 Beneficial)	Negative Number = Lower Impact	
	Primary JST	ANRI (All)	ANRI (Bill Only)
Assessment Result	1.03	-$6,589,261	$3,277,059
ANRI Allocation, impact PER BILL:	N/A	-$0.153109	$0.076146

Each assessment for the portfolio of offerings represents the simple sum of benefits and costs (for the MD EV-JST) or the ratepayer cost increases or decreases (for the two ANRI assessments) each year, combined in an aggregate net NPV of impacts. Since each offering impacts the market in different ways – some change when charging happens, others stimulate increased adoption – the portfolio assessment represents a perspective on how these offerings impact the market when deployed together. The portfolio view also allows for electric utility costs to be captured in the most comprehensive way, and in my view is a good way to consider utility EV program impacts since it provides a single overall assessment of program merit, and accounts for the reality that the programs are impacting the market simultaneously. The portfolio results are both favorable for the MD EV-JST (above 1.0), and for the ANRI-All case (below 0), but unfavorable for the ANRI-bills-only case that ignores externalities.

Q23. Please summarize the assessment results for the OPOB-Only Offering.

A23. Figure 10 summarizes the results of each assessment for the OPOB-Only offering.

Figure 10: All Assessments For The OPOB-Only Offering

Results Summary: OPOB-Only	(>1.0 Beneficial)	Negative Number = Lower Impact	
	Primary JST	ANRI (All)	ANRI (Bill Only)
Assessment Result	0.77	$27,864	
ANRI Allocation, impact PER BILL:	N/A	$0.001214	

The baseline for the Off-Peak/Off-Bill Offering is a customer that has already decided to purchase an EV, and who is charging it using a natural charging pattern (typically, plugging in when returning home from work). The impact of this offering is therefore not to induce adoption, but to change the timing of when an existing EV owner charges their vehicle. Based on real-world measurement of the difference in charging patterns between customers on the OPOB-Only offering and customers in the "natural charging" control group, this assessment quantifies the benefits associated with avoided incremental costs associated with additional PJM-coincident peak load. This offering returns a primary MD EV-JST result less than 1.0 (i.e., not cost-effective), and an unfavorable impact on the ratepayer in both the ANRI-all and ANRI-bills-only scenarios. This unfavorable outcome is mostly likely the result of relatively small pilot program scale. To demonstrate the sensitivity, if the administrative costs had been only $18,000 lower over a multi-year period, the JST for the OPOB-Only offer would have been cost-effective. I therefore consider this outcome a measure of the pilot-scale implementation, which may not be representative of larger-scale offers of similar design.

Q24. Please summarize the assessment results for the residential charger & OPOB Offering.

A24. Figure 11 summarizes the results of each assessment for the residential Charger & OPOB) offering.

Figure 11: All Assessments For The Residential Charger Rebate & OPOB Offering

Results Summary: Charger & OPOB	(>1.0 Beneficial)	Negative Number = Lower Impact	
	Primary JST	ANRI (All)	ANRI (Bill Only)
Assessment Result	0.12	$356,990	
ANRI Allocation, impact PER BILL:	N/A	$0.015553	

As with the OPOB-Only offering (without the charger rebate), this offering's only impact is to change an EV driver's charging behavior. The baseline is an EV owner-operator who has already made the adoption decision,[21] and who charges according to the "natural charging" profile. This offering accomplishes that behavior modification through an off-bill rebate paid in proportion to net-kWhs during the off-peak period, and is a particularly visible way to deliver incentives to customers. It also encourages customers to make use of a networked smart charger approved by the electric utility, and to provide charging data which is critical for assessing impacts. This offering returns a primary MD EV-JST result significantly less than 1.0 (i.e., not cost-effective), and an unfavorable impact on the ratepayer in both the ANRI-all and ANRI-bills-only scenarios. These outcomes, especially compared with the OPOB-Only program, reflect the additional administrative costs associated with delivering the charger rebate.

Q25. Please summarize the assessment results for the Public L2 Offering.

A25. Figure 12 summarizes the results of each assessment for the Public L2 Offering.

[21] The utility providing an incentive for a smart charger, combined with "paying the customer" to charge off-peak, may have an impact on customer adoption, in concert with multiple other factors (unrelated to the utility program) that influence customer EV purchase decisions. Little studies or empirical evidence exists on that dynamic, and it is therefore not captured in the assessment of this offer.

Figure 12: Summary Of All Assessments For The Public L2 Offering

Results Summary: Public L2	(>1.0 Beneficial)	Negative Number = Lower Impact	
	Primary JST	ANRI (All)	ANRI (Bill Only)
Assessment Result	1.07	-$2,432,673	$1,960,003
ANRI Allocation, impact PER BILL:	N/A	-$0.056526	$0.045543

The primary motivation for the public L2 offering is to increase the availability of public charging to reduce range anxiety, provide access to charging (especially for those that may not have access to a charger at home), and increase consumer EV adoption as a result. The primary market impact for this offering is therefore induced EV adoption, and as identified in the Maryland EV-BCA Methodology, the assessments for this offering account for the comprehensive portfolio of benefits and costs (or ratepayer decreases or increases) associated with increased EV adoption. As noted in the methodology section of this testimony, that inventory of impacts is comprehensive and in addition to electric utility program costs, includes factors such as the incremental cost of the EV, federal tax credits, charger costs, increased electricity costs, incremental capacity and transmission costs associated with charging during PJM-coincident peak times, fuel savings, maintenance savings, and increased electric utility revenues, (as appropriate per assessment). The public L2 offering has a favorable outcome for the Primary MD EV-JST, and is also projected to reduce ratepayer costs as quantified through both ANRI assessments. It is also worth noting that administrative costs for all programs include the costs for networking services provided by the charger-vendors, and the costs for data licenses, which are significant elements of the administrative line[22] that impacts this outcome.

Q26. Please summarize the assessment results for the Public DCFC Offering.

A26. Figure 13 summarizes the results of each assessment for the Public DCFC Offering.

Figure 13: Summary Of All Assessments For The Public DCFC Offering

Results Summary: Public DCFC	(>1.0 Beneficial)	Negative Number = Lower Impact	
	Primary JST	ANRI (All)	ANRI (Bill Only)
Assessment Result	1.01	-$4,541,443	$932,202
ANRI Allocation, impact PER BILL:	N/A	-$0.105526	$0.021661

As with the Public L2 offering, the Public DCFC offering is assessed based on the impacts associated with the increased EV adoption induced by the availability of additional fast charging in the market. This offering realizes a favorable outcome under the primary MD EV-JST with a ratio of the NPVs of benefits divided by costs being >1.0. Both ANRI assessments are also favorable, indicating that ratepayer costs (in the ALL case) go down. It is worth noting that this particular program was implemented during the COVID-19 Global Pandemic. These conditions are especially impactful for the construction-cost intensive DCFC program, and the BCA outcomes were likely negatively impacted by significant supply-chain constraints and other related factors.

Q27. Are there additional qualitative factors that should be taken into consideration regarding the PE EV Programs?

[22] These networking and data costs are also applicable for the public DCFC offer as well, and are mostly the result of charger-company pricing policies rather than factors directly under PE's control.

A27. Yes. The Maryland EV-BCA Methodology allows for consideration of additional strategic factors that provide important context for the four quantitative assessments summarized above. Several of these strategic considerations became evident when preparing this analysis, and I believe they provide important context for considering the quantitative results:

1. **Scale:** All of the current electric utility EV pilot programs are relatively small scale, and that typically drags down BCA outcomes. A primary reason is utility administrative costs that include some fixed costs, but which are diluted as program scale increases. The results presented in this testimony reflect the currently approved programs, at their current relatively small size, and may not reflect the net benefit of potential larger scale programs.
2. **Start-up Investment:** This assessment has been done during the mid-point of an initial set of electric utility EV pilot programs. There are hard-to-document costs associated with new programs such as these, such as organizational learning, Information Technology investments, process infrastructure, and consumer awareness development. Although those costs have been captured in this analysis in some cases, the extent to which those early-phase investments can be leveraged with larger-scale offerings longer term is probably under-represented.
3. **Untapped Potential:** The residential managed charging program, especially the OPOB program, establishes a platform that enables more advanced managed charging capabilities beyond what are currently being realized. More advanced "grid interactive" opportunities may be made possible by the platform being

developed, and if leveraged, could deliver benefits beyond those captured in the current analysis. The potential for leveraging the platform being developed is important context for considering the net benefit of the current utility EV programs.

4. **Unquantified Benefits:** As defined in the Maryland EV-BCA Methodology, this portfolio of assessments focuses on hard measures that can be quantified, like program costs, emissions reductions, and impacts on electricity costs. There are other potential benefits associated with widespread EV adoption that are not yet accommodated fairly in this methodology, with two primary examples being improved vehicle safety and the strategic benefits of diversifying energy sources for transportation. Regarding the latter point, it is important to note that the transportation system in the United States is overwhelmingly based on a single source of energy (petroleum); by contrast, EVs can be powered from any electricity sourced from any generation fuel type. Increased EV adoption, especially if optimized to minimize additional loading during peak time, is a primary strategy for reducing those strategic vulnerabilities. Neither the safety nor reduced-petroleum-use considerations are represented fairly in the current methodology.

5. **The Value of Charging Data:** As noted in the methodology section of this testimony, these assessments depend heavily on knowing customer EV charging behaviors. These programs encourage the deployment of networked smart chargers, or networked public chargers, and collect detailed charging transaction data. That data itself is extremely valuable, and in addition to its use for policy analysis (such as these BCA and ratepayer impact assessments), could help inform

long term grid loading analysis, and optimal program design. The value inherent in the data captured through these programs is not quantified in this analysis, and in my view is an important factor in considering the merit of the electric utility EV programs.

IV. CONCLUSIONS

Q28. In summary, what were the results of your analysis?

A28. This testimony summarizes the results of a detailed analysis performed on the PE EV Pilot program portfolio using the MD EV-BCA Methodology defined by the EV-BCA work group in 2021, and approved by the Commission in January of 2022. The combination of these assessments provides multiple perspectives on the merit of each offering and the portfolio of offerings when considered together. The portfolio, public L2, and public DCFC programs deliver a MD EV-JST above 1.0, and also delivers cost reductions for ratepayers when externalities are included. The two residential programs are not cost-effective at the current level of scale, and they also increase net-costs to ratepayers even under the ANRI-All case. The ANRI-Bills-Only case was unfavorable, which implies ratepayer costs would go up slightly, when the impact of externalities are considered. The Market-Wide assessment demonstrated that widespread electrification overall was beneficial in all cases considered, especially in the scenario where managed residential charging becomes dominant. All of these results are strongly impacted by the small scale of the currently approved pilot offers, but can be used to compare relative effectiveness of similar programs to guide program optimization and prioritization.

Q29. Does this conclude your Direct Testimony?

A29. Yes, but I reserve the right to modify this analysis or conclusions if new information is made available.