

**BEFORE THE  
PUBLIC SERVICE COMMISSION OF MARYLAND**

Potomac Electric Power Company's  
Application for Adjustments to its Retail Rates  
for the Distribution of Electric Energy

CASE NO. 9820

DIRECT TESTIMONY

OF

DUSTIN MADSEN, CPA, CA (CAN), CPA (CAN), CDP, CRRA

ON BEHALF OF THE OFFICE OF PEOPLE'S COUNSEL

JANUARY 30, 2026

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**DIRECT TESTIMONY OF  
DUSTIN M. J. MADSEN**

**INTRODUCTION**

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

2 A. My name is Dustin M. J. Madsen. My business address is 401 Ryland St. Suite  
3 200-A, Reno, NV 89502.

4 **Q. Please describe your educational background and qualifications.**

5 A. I have more than 20 years of experience in auditing, accounting, and regulated  
6 businesses. I am a Certified Public Accountant registered with the Illinois  
7 Department of Financial and Professional Regulation. I am also a Certified  
8 Depreciation Professional with the Society of Depreciation Professionals and a  
9 Certified Rate of Return Analyst with the Society of Utility and Regulatory  
10 Financial Analysts. I am also a Canadian Chartered Professional Accountant and  
11 Chartered Accountant. My curriculum vitae is attached to this testimony as  
12 Appendix 1 and provides a complete description of my qualifications, regulatory  
13 and professional experience.

14 I have provided consulting services and been accepted as an expert before  
15 regulators on a wide range of issues, including but not limited to cost-of-service,  
16 rate design, cost allocation, revenue requirements, prudence assessment,  
17 depreciation, cost of capital, income taxes, deferral accounts, working capital,  
18 business valuation, and information technology.

1           Prior to forming my consulting practice, I held the position of Manager of  
2           Regulatory, Manager of Forecasts and Budgets, and Manager of Tax in a large  
3           regulated electric distribution utility with a multi-national parent (Fortis Inc.)  
4           owning utilities in both the United States and Canada. Subsequently, I provided  
5           consulting services for AltaLink, which is a large electric transmission utility  
6           owned and operated by Berkshire Hathaway Energy. While in these roles, I was  
7           responsible for the preparation and defense of all regulatory applications,  
8           including general rate applications, deferral applications, cost of capital  
9           applications, debt applications, various miscellaneous applications, and appeal  
10          application filings.

11           I also provided consulting services to Berkshire Hathaway Energy related  
12          to business acquisitions and valuations, where I constructed a model to support the  
13          acquisition and valuation of various utilities. Since leaving Berkshire Hathaway  
14          Energy in 2016, I have provided consulting services to regulators, interveners, and  
15          utilities on a broad base of issues.

16   **Q.   Have you previously testified in regulatory proceedings on utility rates?**

17   **A.**   Yes. I have testified before the Arizona Corporation Commission, Mississippi  
18          Public Service Commission, New York Public Service Commission, and the  
19          Public Utilities Commission of Ohio on multiple occasions, as well as before the  
20          North Carolina Utilities Commission, Public Service Commission of South

1 Carolina, and numerous regulators in Canada, including in Alberta, Manitoba,  
2 New Brunswick, Nova Scotia, and Ontario, and the Northwest Territories.

3 **Q. On whose behalf are you appearing?**

4 A. I am presenting testimony on behalf of the Office of People’s Counsel (“OPC”).

5 **Q. Please summarize the company’s application in respect of revenue**  
6 **requirement matters.**

7 A. On October 14, 2025, Potomac Electric Power Company (“Pepco” or the  
8 “company”) submitted its Application for Adjustment to its Retail Rates for the  
9 Distribution of Electric Energy (the “Application”). Included within the  
10 Application was a proposed revenue requirement based on a fully forecasted test  
11 year (“FFTY”). The FFTY is supported by Witness Robert T. Leming and  
12 proposes a total increase in revenue requirement of \$133.2 million.<sup>1</sup>

13 Additionally, pursuant to the Maryland Public Service Commission’s  
14 (“Commission”) directive in Order No. 91181 for Pepco’s rate application to be  
15 “accompanied by the requisite information needed to calculate a historic test  
16 year,”<sup>2</sup> the company calculated a stand-alone revenue requirement based on a  
17 single historic test year—what the company calls its traditional test year  
18 compliance filing (“TTYCF”). The TTYCF is supported by company Witness

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<sup>1</sup> Direct Testimony of Robert T. Leming (Part II) (“Leming Direct II”), Schedule (RTL)-1 at 1.

<sup>2</sup> Md. Pub. Serv. Com’n., Order No. 91181 at 30, *Potomac Electric Power Company's Application for Adjustments to its Retail Rates for the Distribution of Electric Energy* (Case No. 9702, June 10, 2024).

1           Conor Nelson and proposes a total increase in revenue requirement of \$118.2  
2           million.<sup>3</sup>

3                     The major drivers contributing to the increase in the FFTY and TTYCF  
4           revenue requirements are an increase in net plant, higher operating expenses, and  
5           higher proposed rate of return on rate base.

6   **Q.    What is the purpose of your testimony in this proceeding?**

7   A.    First, I discuss why the Commission should deny Pepco's request to set rates using  
8           a fully forecasted test year and recommend the Commission authorize rates based  
9           on the historic test year data provided in the TTYCF. Second, I calculate a revised  
10          TTYCF revenue requirement, based on my own recommended adjustments to  
11          operations and maintenance expenditures ("O&M") and taxes, as well as the  
12          adjustments to plant in service and cost of capital recommended by OPC witnesses  
13          Colin T. Fitzhenry and David Garrett. Finally, while I do not recommend the  
14          Commission approve rates based on a fully forecasted test year, I calculate a  
15          revised FFTY revenue requirement, which includes my own recommended  
16          adjustments for O&M and taxes, as well as adjustments from OPC witnesses  
17          Fitzhenry and Garrett to plant-in-service and cost of capital.

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<sup>3</sup> The company's initial application included a TTYCF revenue requirement of \$141.7 million. Direct Testimony of Conor Nelson, Schedule (CN)-1 at 1. The supplemental testimony filed on December 18, 2025 revised the TTYCF revenue requirement to \$118.2 million. Supplemental Direct Testimony of Conor Nelson ("Nelson Supplemental Direct"), Schedule (CN-SD)-1.

1 **Q. Have you prepared schedules to accompany your testimony?**

2 A. Yes. Exhibit DMM-1 sets forth my revised TTYCF revenue requirement. Exhibit  
3 DMM-2 sets forth my revised FFTY revenue requirement.

4 **I. Summary and Recommendations**

5 **Q. Please summarize your recommended revenue requirement in this case.**

6 A. I recommend the Commission deny Pepco's request for a revenue requirement  
7 based on a future test year and, instead, authorize a revenue requirement based on  
8 the Commission's standard historic test year methodology. The company's  
9 proposed FFTY erodes sufficient cost containment incentives, does not provide  
10 any meaningful benefits to customers relative to the use of a historic test year, and  
11 shifts significant risks of projected test year costs on to customers. Accordingly, I  
12 recommend a revenue reduction of \$7.5 million—reflecting certain adjustments to  
13 Pepco's TTYCF revenue requirement recommended by myself and OPC's other  
14 witnesses. My proposal is set forth the figure below and supported by Exhibit  
15 DMM-1:

*Continued onto following page*

1

*Figure 1 – Summary of proposed revenue requirement*

(Thousands of Dollars)	<b>12 Months Ended September 30, 2025</b>		
	Average Unadjusted	Ratemaking Adjustments	MD Adjusted
	(1)	(2)	(3)
<b>OPERATING INCOME</b>	\$ 185,378	\$ 2,580	\$ 187,958
<b>ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION</b>	\$ 7,886	\$ (2,743)	5,143
<b>OPERATING INCOME FOR RATE OF RETURN CALCULATION</b>	<b>\$ 193,264</b>	<b>\$ (163)</b>	<b>\$ 193,101</b>
<b>RETURN ON RATE BASE</b>	<b>6.36%</b>		<b>6.33%</b>
Less Weighted Cost of Long-Term Debt	2.85%		2.85%
Net amount available for common equity	3.51%		3.49%
Common Equity ratio	43.00%		43.00%
	<b>For Informational Purposes Only</b>		
<b>Earned MD Jurisdictional Return on Equity</b>	<b>8.17%</b>		<b>8.11%</b>
Requested Rate of Return			6.16%
<b>Cumulative Revenue Requirement</b>	<b>\$ (8,642)</b>	<b>\$ 1,112</b>	<b>\$ (7,530)</b>
<b>Projected Earned ROE</b>			<b>7.70%</b>
<b>Total Distribution Revenues, Adjusted</b>			<b>\$ 835,582</b>

2

3

However, if the Commission chooses to set a rate based on Pepco’s

4

proposed FFTY approach, I recommend a revenue reduction of \$2.5 million

5

reflecting certain adjustments to Pepco’s FFTY revenue requirement

6

recommended by myself and OPC’s other witnesses. This recommendation is

7

supported by Exhibit DMM-2.

1 **II. The Commission should deny Pepco’s proposed FFTY.**

2 **Q. What is the company’s FFTY proposal?**

3 A. The company’s FFTY proposal reflects a \$133.2 million revenue requirement  
4 increase, based on forecasted capital and O&M expenditures for January 1, 2026  
5 through December 31, 2026 and a 10.50% return on equity.<sup>4</sup> Unlike future test  
6 years authorized through multi-year rate plans—which expire at the conclusion of  
7 the test year period—Pepco’s FFTY is a stated rate and will remain effective until  
8 new rates are set. For the typical electricity customer, Pepco’s proposal will result  
9 in an \$11.73 increase to a customer’s monthly distribution bill.<sup>5</sup> The proposed  
10 rates would be set based on a forecasted test year for the twelve months ending  
11 December 31, 2026, and would be effective until new rates are set.

12 **Q. What explanation does the company provide for why it is proposing to use set**  
13 **rates based on a fully forecasted test year?**

14 A. The company describes its proposal as an “interim approach” having regard for  
15 “the Commission’s evolving framework for alternative rate making.”<sup>6</sup> The  
16 company also further claims that the benefits of an FFTY are similar to those of  
17 multiyear rate plans (“MRPs”), in that an FFTY would reduce regulatory lag,  
18 increase transparency, and improve cost recovery alignment.<sup>7</sup> Finally, the  
19 company suggests that the FFTY revenue requirement results in a lower revenue  
20 requirement than determined under the standard historical test year approach.<sup>8</sup>

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<sup>4</sup> Errata to Direct Testimony of Robert T. Leming (Part I) (“Leming Direct I”) at 6:3-5.

<sup>5</sup> *Id.* at 7:20-23.

<sup>6</sup> *Id.* at 8:11-13.

<sup>7</sup> Leming Direct I at 8:13-16.

<sup>8</sup> Leming Direct II at 8:8-14.

1           However, as of Pepco's December 18, 2025, updated TTYCF filing, this is no  
2           longer the case.<sup>9</sup> In fact, Pepco's updated TTYCF revenue requirement is \$15.0  
3           million lower (\$133.2 million FFTY - \$118.2 million TTYCF)<sup>10</sup> than the proposed  
4           FFTY revenue requirement.

5   **Q.    Is the company's proposal appropriate as an interim measure?**

6   A.    No. As I explain below, the standard historical test year approach is far more  
7           reliable and has long been accepted by the Commission in the setting of rates that  
8           are just and reasonable. The FFTY proposal advanced by the company provides no  
9           protections for customers and improperly relies on a projection of what might  
10          happen rather than what is known.

11 **Q.    How is Pepco's FFTY different from a rate set using a historic test year?**

12 A.    The key difference relates to the inputs. In an FFTY, the revenue requirement is  
13          based on utility forecasts for O&M expenditures, additions to plant, and expected  
14          revenues over the future test year period. Under a historic test year, the revenue  
15          requirement is based on the company's actual plant-in-service balance, O&M  
16          expenditures, and revenues for the historic test year period. Though some  
17          forecasting and judgment is exercised in making adjustments to a historic test  
18          year, the revenue requirement is largely based on actual data and experience,  
19          rather than estimates or projections.

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<sup>9</sup> In his supplemental direct testimony, Pepco witness Nelson indicates that an updated FFTY filing will be provided in rebuttal testimony. *See* Nelson Supplemental Direct at 3:20-22.

<sup>10</sup> Leming Direct II, Schedule (RTL)-1 and Nelson Supplemental Direct (CN-SD)-1.

1 **Q. Are there any drawbacks from using forecasts to determine rates?**

2 A. Certainly. Forecasts require significant judgment, and relate to costs that have not  
3 been spent, and indeed may not be spent in the future. As a former manager within  
4 a large, regulated electric distribution utility, I have witnessed firsthand how such  
5 judgment is exercised. Utilities retain discretion and control over the investments  
6 they choose to make. The accuracy of a utility's projections is driven, in large part,  
7 by how a utility exercises control over the costs it incurs.

8           However, utilities are for profit entities that also seek to maximize profits  
9 for its shareholders. Unless a change in costs is truly outside of management's  
10 control (i.e., a change in tax rates), utilities are incentivized to overstate the level  
11 of spending required to safely and reliably serve customers. And if the rates  
12 customers pay are entirely dependent on utility forecasts, a utility has a large  
13 incentive to propose a far more ambitious capital investment plan than it actually  
14 would implement. Thus, it is important to take projections with a grain of salt  
15 because it is difficult to forecast accurately and, in the ratemaking context, utilities  
16 have an incentive to overstate their spending needs.

17 **Q. How does the company claim its FFTY reduces regulatory lag?**

18 A. Regulatory lag represents the period between when a cost is incurred and when it  
19 is recovered in rates. The company suggests that its FFTY proposal reduces  
20 regulatory lag because it allows the company to recover costs it expects to incur in

1 the near future, rather than at a later date after a subsequent rate case.<sup>11</sup> The  
2 company also suggests that regulatory lag is greater under periods of high capital  
3 investment or inflationary pressures.<sup>12</sup>

4 **Q. Please explain what the company means when it claims that the FFTY will**  
5 **improve cost recovery alignment?**

6 A. The company's claim for improved cost recovery alignment appears to focus on  
7 the reduction of regulatory lag. Specifically, the company appears to suggest that  
8 reducing regulatory lag will improve its ability to earn its authorized rate of  
9 return.<sup>13</sup>

10 **Q. Does the FFTY reduce regulatory lag relative to a standard test year?**

11 A. Pepco's proposed FFTY does not materially reduce regulatory lag relative to the  
12 TTYCF. At best, assuming Pepco's new rates go into effect in August 2026, the  
13 benefits of reduced regulatory lag would be limited to the five-month period  
14 ending on December 31, 2026, and only for projects Pepco *actually* places into  
15 service. As of January 1, 2027, Pepco's FFTY would have the same effect on  
16 regulatory lag as its TTYCF.

17 Moreover, because the historic test year approach relies on historic, known  
18 and measurable data for the rate effective period, the TTYCF revenue requirement

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<sup>11</sup> Leming Direct I at 9:11-22.

<sup>12</sup> *Id.* at 4:8-10.

<sup>13</sup> Leming Direct II at 4:4-21.

1 is better aligned with actual costs the company is likely to incur during the rate  
2 effective period.

3 **Q. What is Pepco’s explanation for how its FFTY improves transparency?**

4 A. Pepco suggests a projected test year approach “promotes transparency for  
5 customers and stakeholders into utility operating plans and the rates necessary to  
6 support them.”<sup>14</sup>

7 **Q. Does the FFTY improve transparency compared to the use of a standard**  
8 **historic test year?**

9 A. Not in any meaningful sense. While a projected test year may include information  
10 regarding what the company plans to construct, the utility retains discretion as to  
11 the projects it pursues and the costs that are actually incurred.<sup>15</sup> Setting rates based  
12 on actual costs provides far more transparency for customers.

13 **Q. Are there any risks to customers that result from setting rates based on utility**  
14 **forecasts?**

15 A. Yes. As I’ve noted above, the primary risk with a FFTY is the reliability and  
16 accuracy—and lack thereof—of the utility’s forecasting. A utility’s actual  
17 performance can significantly deviate from its projections. Since the utility—and  
18 not customers—controls how it manages its operations, inflated or inaccurate  
19 forecasts can result in customers paying for costs that the utility actually does not  
20 incur. This is a significant risk that is not present in historic test year ratemaking.

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<sup>14</sup> Leming Direct II at 4:15-19.

<sup>15</sup> *E.g.*, Md. Pub. Serv. Com’n, *Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan*, Order No. 89678 at 96–97 (Case No. 9645, Dec. 16, 2020) (noting that the utility retains discretion in determining which projects it may “elect to construct”).

1           A related risk is that the forecasts put forward by the company can be  
2 overstated, as shown by the significant adjustments to the FFTY I recommend. In  
3 such circumstances, customers are not only paying for costs greater than what is  
4 required to serve them, but also paying for projects that the utility may likely defer  
5 to a subsequent year.

6           In past testimony in other jurisdictions, I have characterized forecasts of  
7 this nature by a utility as a “wish list.” Put differently, because utilities largely  
8 control the timing of their investments, the forecasts largely reflect the cost for any  
9 projects and costs the company would like to pursue and place into service in the  
10 forecasted test year, regardless of whether those investments actually are made.  
11 This is perhaps best illustrated by inflated capital and labor cost forecasts in most  
12 forecasted test years. These inflated forecasts often present a reality that is not  
13 realistically achievable such as the retention of far more skilled staff than are  
14 available to be retained or the completion of a volume of capital projects that is  
15 simply not feasible in the time period presented. I comment further on certain of  
16 the company’s forecasts in the FFTY below based on this context.

17 **Q. If the FFTY rate was less than the rate resulting from the TTYCF, would**  
18 **customers be better off?**

19 A. No, and any implication suggesting otherwise simply lacks merit because the two  
20 calculations are fundamentally different, as I have outlined herein. As discussed  
21 above, the TTYCF is based on a historical test year approach and more closely

1 reflects actual costs required to serve customers. By comparison, the FFTY is  
2 based on assumptions about costs the company may incur over a future period.

3 To illustrate this point, I note that Pepco's adjusted TTYCF net electric  
4 plant balance equals \$3.714 billion.<sup>16</sup> Comparatively, the company's adjusted net  
5 electric plant balance under the FFTY is \$3.585 billion.<sup>17</sup> The difference between  
6 these two balances—one based on actuals and another based on forecasts—  
7 suggests the company exercised a degree of discretion and judgment when  
8 determining what costs it chose to include in its FFTY. Indeed, the company  
9 controls which investments it places into service and likely could have forecasted  
10 a higher net electric plant balance compared to what Pepco's proposed FFTY  
11 represents.

12 In short, the FFTY revenue requirement the company proposes merely  
13 reflects the scope of capital and O&M spending that the *company* believes  
14 customers can bear, and not the costs that are necessary to provide safe and  
15 reliable service. In contrast, a rate based on a historic test year is a more realistic  
16 assessment of the actual costs customers should be paying.

17 **Q. Do you agree with the company's proposal to set rates using a forecasted test**  
18 **year?**

19 **A.** No. The Commission should deny the company's requested FFTY in its entirety.

20 For the reasons discussed above, it is my opinion that Pepco's proposal is neither

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<sup>16</sup> Nelson Supplemental Direct, Schedule (CN-SD)-1 at 1.

<sup>17</sup> Leming Direct II, Schedule (RTL)-1 at 2.

1 aligned with the public interest nor core principles of utility regulation. Utilities,  
2 not customers, should bear the risk of forecasting errors, and customers should pay  
3 no more than the *actual* costs required to serve them.

4 **Q. What are the main benefits setting rates using a historic test year?**

5 A. There are a number of benefits to setting rates using a historic test year. First,  
6 historic test year ratemaking includes strong incentives to control current and  
7 future spending at historical actual cost levels. This is because such rates are based  
8 primarily on known costs that the company will incur. Basing rates on known  
9 costs removes some of the risk that the company will receive recovery in rates of  
10 amounts that may not be spent. Once the rates are authorized for the Company  
11 those rates remain in effect until the utility proposes and the Commission approves  
12 new rates. Second, customers only pay for projects that are actually in service.  
13 Third, utilities have less of an incentive to propose a wish list of projects, since  
14 historic test year rates do not provide for advanced recovery of costs before the  
15 costs have been incurred. Ultimately, historic test year rates are more consumer  
16 protective and reasonably align the utility's cost recovery interests with the  
17 principle that customers should pay no more than what is required to ensure safe  
18 and reliable service.

19 **Q. Which revenue requirement do you recommend be used to set Pepco's rates**  
20 **for customers in this matter?**

21 A. I recommend the Commission set rates based on a historic test year, using Pepco's  
22 proposed TTYCF as a starting point. Below, in section IV of my testimony, I

1 recommend several adjustments to Pepco's TTYCF revenue requirement. The  
2 resulting revenue requirement more realistically reflects the company's actual  
3 costs and is sufficient to ensure the company can continue providing safe and  
4 reliable service to customers at just and reasonable rates.

5 **III. Pepco's proposed regulatory assets for exogenous cost recovery should be**  
6 **denied.**

7 **Q. Has the company proposed any unique cost-recovery mechanisms in addition**  
8 **to the FFTY?**

9 A. Yes. The company has proposed regulatory assets for exogenous costs, which the  
10 company defines as "costs driven by external factors largely outside of the utility's  
11 control such as storm costs and pension expense."<sup>18</sup>

12 The proposed regulatory asset would allow for any increase or decrease in  
13 the company's minor storms and pension expense. A separate deferral for  
14 incremental major storms O&M expense is already approved for the company.<sup>19</sup>

15 In addition to minor storms and pension expense, the company is also  
16 proposing to include other exogenous events, broadly defined as including "any  
17 new legislative, regulatory, or other public policy requirements, including changes  
18 in accounting rules, that have an impact on the company's cost of service and  
19 emerge after the filing and approval of this proceeding be allowed to be deferred

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<sup>18</sup> Leming Direct II at 10:7-8.

<sup>19</sup> *Id.* at 11:18-21.

1 into a regulatory asset/liability for prudency review in a future base rate case  
2 proceeding.”<sup>20</sup>

3 **Q. What is the company’s justification for its proposed recovery mechanisms?**

4 A. The company considers the costs covered by the mechanisms to be  
5 “unpredictable,” “outside of the utility’s control,” and a cause of rate volatility.<sup>21</sup>  
6 Accordingly, the company asks the Commission to allow it to defer the impact of  
7 such costs.<sup>22</sup>

8 **Q. Has Pepco asked the Commission to adopt this type of mechanism before?**

9 A. Yes. In the MRP Lessons Learned proceeding held in 2024, Pepco and its sister  
10 utilities proposed a similar mechanism for the recovery of exogenous costs as a  
11 modification to the MRP construct.<sup>23</sup> As of the date of the filing of this testimony,  
12 the Commission has not issued an order in that proceeding and the issue is still  
13 pending.

14 **Q. Do you recommend approval of a regulatory asset specific to minor storms**  
15 **expense?**

16 A. No. I recommend the Commission deny the company’s request. I am concerned  
17 that approving Pepco’s proposal will further erode the company’s incentive to  
18 control spending on these costs. Specifically, when a regulatory account is  
19 approved, it transfers, subject to a prudence assessment, all forecasting risk for

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<sup>20</sup> *Id.* at 12:20-23 and 13:1.

<sup>21</sup> *Id.* at 10: 7-10.

<sup>22</sup> Leming Direct II at 11:5-7.

<sup>23</sup> Reply Comments of Potomac Electric Power Company and Delmarva Power & Light Company, at 10, ML# 312731 (Case No. 9618, Oct. 4, 2024) (proposing an “exogenous cost regulatory asset”).

1 that cost to customers. Utilities have little incentive to manage within their  
2 budgets—or improve their forecasting accuracy—if costs can simply be excluded  
3 from any budgeting consideration. Pepco cannot control whether a minor storm  
4 occurs. But Pepco can, however, control how it responds to the storm. Establishing  
5 a regulatory asset shifts cost risks with how the company responds to a minor  
6 storm event away from the company and onto its customers. Moreover, given the  
7 significant information asymmetry utilities have over the Commission and  
8 intervenors, it is incredibly difficult for intervenors to challenge a utility's claim  
9 that such spending was imprudent. It is far more consumer protective to retain  
10 what incentives exist for Pepco to control its costs in areas that it can, such as how  
11 it responds to minor storm events.

12 **Q. If storms are outside of the utility's control, should all storm costs be treated**  
13 **similarly?**

14 A. No. Unlike major storm expenses, minor storms are best considered as a standard  
15 operational risk that utilities should expect and be prepared to handle. It makes  
16 little sense to de-risk these costs. While minor storm costs can vary, they do not  
17 vary to such an extent that would warrant approval of a regulatory asset.<sup>24</sup>

18 **Q. Are you aware of the Commission or any other regulator approving a**  
19 **regulatory account for minor storm expenses?**

20 A. No. While I am familiar with other utilities having requested similar regulatory  
21 accounts for minor storms expense, including in New York, I am unaware of any

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<sup>24</sup> See Pepco response to OPC DR 6-19.

1 regulator having approved such a request. Pepco confirmed that the Commission  
2 has not authorized a similar request and that it did not analyze other  
3 jurisdictions.<sup>25</sup> Furthermore, the FFTY spans January 1, 2026 to December 31,  
4 2026, which is a single future test year. The forecast risk for a single year is not  
5 material enough to warrant approval of a new deferral account. In summary, the  
6 above evidence supports the denial of the minor storms expense regulatory  
7 account.

8 **Q. Do you agree with the company’s proposal to establish a regulatory asset for**  
9 **“legislative, regulatory, or other public policy requirements”?**

10 A. No. The company is effectively seeking approval to defer unquantifiable costs for  
11 future prudence review. The limits on an exogenous deferral as proposed by the  
12 company are extremely broad. Beyond a commitment to identify an event within  
13 90 days, the company includes no limiting principles on how it defines  
14 “legislative, regulatory, or policy requirements.”<sup>26</sup> Approval of such an account  
15 would be unprecedented and would also materially erode Pepco’s risk profile  
16 relative to its peers.

17 More specifically, Pepco’s proposal eliminates many of the ordinary  
18 forecast risks utilities historically experience. In exchange for a monopoly right to  
19 serve its customers, and earn a fair return on its investment, the utility consents to  
20 being regulated. It is the utility, not customers, that should bear reasonable risks of

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<sup>25</sup> Pepco response to OPC DR 6-20.

<sup>26</sup> Leming Direct II at 14:19 – 15:7.

1 complying with the regulatory obligations. In that regard, the company's proposal,  
2 if approved, would fundamentally reduce its risk relative to its peers, which would  
3 be appropriately considered in any approved return on equity.

4 Accordingly, I recommend the broader exogenous event regulatory account  
5 be denied.

6 **Q. Do you take any position on the company's proposed pension expense**  
7 **regulatory asset?**

8 A. The final element of the company's proposal is the pension expense regulatory  
9 asset. In this case, I agree that the company does not have control over the cost and  
10 the variances may be material. Moreover, unlike how a utility responds to minor  
11 storm events, volatility in pension expense is not an operational cost which  
12 utilities can take steps to contain. Accordingly, I do not oppose establishing a  
13 regulatory asset limited to pension expense.

14 **IV. Adjustments to Pepco's TTYCF Revenue Requirement**

15 **Q. Please summarize this section of your testimony.**

16 A. In this section of my testimony, I present my recommended revenue requirement,  
17 including adjustments to rate base and O&M expense. Using Pepco's TTYCF as a  
18 starting point, I have calculated a total reduction of \$7.5 million to Pepco's  
19 currently effective revenue requirement. This amount is reflected in Exhibit  
20 DMM-1, on Schedule A.

1       **A.   Rate Base**

2       **Q.   Does your revenue requirement incorporate any disallowances recommended**  
3       **by OPC witness Fitzhenry?**

4       A.   Yes. Mr. Fitzhenry's testimony recommends two disallowances for capital  
5       investments placed into service between April 2024 and September 2025.<sup>27</sup> Those  
6       adjustments resulted in a decrease in rate base of \$46.0 million and are reflected in  
7       my proposed TTYCF revenue requirement through ratemaking adjustment  
8       ("RMA") 1 on Schedule C-1 of DMM-1.

9       **Q.   Do you propose any adjustments to the company's TTYCF rate base?**

10      A.   Yes. I recommend the Commission direct the removal of the company's RMA 3  
11      and 4 in relation to the inclusion of post test year reliability closings the company  
12      forecasts to go into service after April 2026. These two adjustments reduce the  
13      company's rate base by \$84.4 million.

14      **Q.   What does RMA 3 and RMA 4 represent?**

15      A.   These adjustments reflect costs that will be added to rate base beginning in April  
16      2026 and extending to July 2027. According to Pepco witness Nelson, RMA 3  
17      "reflects the impact of the known and measurable costs in construction work in  
18      progress ("CWIP") for reliability projects as of September 30, 2025 and that are  
19      forecasted to be placed into service in April 2026 through July 2026, prior to the  
20      rate effective date."<sup>28</sup> RMA 4 "reflects the impact of the known and measurable

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<sup>27</sup> Direct Testimony of Colin T. Fitzhenry ("Fitzhenry Direct") at 40, Table CTF-4.

<sup>28</sup> Nelson Direct at 13:20-23.

1 costs in CWIP for reliability projects as of September 30, 2025 and that are  
2 forecasted to be placed into service from August 2026 – July 2027, through the  
3 rate effective period in this proceeding.”<sup>29</sup> The company further assures that the  
4 projects do not generate new revenue and will be closed to plant before the rate  
5 effective date.<sup>30</sup> The total adjustments proposed to rate base net of retirements are  
6 \$35.06 million for RMA 3 and \$61.03 million for RMA 4.<sup>31</sup>

7 **Q. Has the Commission previously approved recovery of post-test year**  
8 **reliability plant closings?**

9 A. Yes. But significantly, the Commission has never authorized recovery for  
10 reliability plant closings forecasted for after the conclusion of the evidentiary  
11 hearings. Longstanding Commission precedent limits recovery for post-test year  
12 plant closings to “actual, prudently incurred costs for non-revenue producing  
13 safety and reliability investments that are completed before the hearing date and  
14 that are known and measurable.”<sup>32</sup>

15 **Q. Does RMA 3 and 4 align with the Commission’s exception based on the**  
16 **precedent noted above?**

17 A. No. While a portion of the post-test year plant included in RMA 3, which covers  
18 April to July 2026, may be in-service prior to the hearing commencement date of  
19 April 27, 2026, most will not be. Additionally, none of the plant proposed to be

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<sup>29</sup> *Id.* at 13:23 – 14:3.

<sup>30</sup> *Id.* at 14:3-5.

<sup>31</sup> Nelson Supplemental Direct, Schedule (CN-SD)-1 at 8 and 9.

<sup>32</sup> *E.g.*, Md. Pub. Serv. Com’n, Order No. 90847 at 12, *The Potomac Edison Company’s Application for Adjustments to its Retail Rates for the Distribution of Electric Energy* (Case No. 9695, Oct. 18, 2023).

1 included in RMA 4 will be in-service before the hearing commencement date. Of  
2 the \$104.9 million included in the total adjustment in RMAs 3 and 4, only \$11.677  
3 million relates to plant closings prior to the start of the evidentiary hearings in  
4 April 2026.<sup>33</sup>

5 **Q. Does Pepco provide any justification for a need to depart from such**  
6 **longstanding Commission practice?**

7 A. No. Pepco continues to rely solely on its consideration that the reliability projects  
8 “do not generate any revenue” and “will be providing service to customers for the  
9 entirety of the rate effective period.”<sup>34</sup> Despite relying on these facts, the company  
10 provides no explanation of why inclusion of reliability plant closings forecasted  
11 for after the evidentiary hearings is appropriate.

12 **Q. What impact does removing RMA 3 and RMA 4 have on the TTYCF revenue**  
13 **requirement?**

14 A. My recommended adjustments reduce Pepco's TTYCF rate base by \$84.4 million  
15 with consequential impacts on depreciation, return and income taxes. The  
16 adjustments to remove these amounts are shown on Schedule C-3 and C-4 of  
17 Exhibit DMM-1.

18 **Q. Are there any other recommendations you propose?**

19 A. Yes, I also recommend an adjustment to RMA 2. Mr. Nelson proposes this  
20 adjustment to reflect the “known and measurable effects of reliability projects”

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<sup>33</sup> ML# 325456, Pepco MD Supplemental Supporting Data I.N.A2-4 (Case No. 9820, Dec. 18, 2025).

<sup>34</sup> Nelson Direct at 14:3-8.

1 that close from October 2025 — March 2026. Consistent with Commission  
2 precedent, I recommend that RMA 2 be updated to reflect the actual and known  
3 and measurable reliability projects that close between October 2025 and April 27,  
4 2026, the date that evidentiary hearings commence. This change aligns with my  
5 proposed adjustment to RMA 3 noted above.

6 **B. Operating Revenues**

7 **Q. Please describe RMA 6 to the TTYCF revenue requirement.**

8 A. As explained by the company RMA 6 “annualizes the billed distribution revenues  
9 to levels set in Order No. 91181 in Case No. 9702” which is “necessary to reflect a  
10 full annual amount of distribution revenues at the levels set in Case No. 9702 for  
11 the company’s streetlight classes.”<sup>35</sup>

12 **Q. Did the company make any other adjustment to its operating revenues to**  
13 **reflect changes in billing determinants in the Test Year and rate effective**  
14 **period?**

15 A. No. It does not appear that any further adjustments were made.

16 **Q. Why is this important?**

17 A. The operating revenues in the test year should reflect the revenues the company  
18 expects to receive from its customers as of the rate effective date. By not adjusting  
19 the revenues, as the company appears to have done, the company is implying that  
20 the level of customers and consumption will mimic historical experience. This is

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<sup>35</sup> Nelson Direct at 16:4-7.

1 of course, not likely to be the case as additional customers and load may likely be  
2 added to the system throughout the rate effective period.

3 **Q. Why does the company's operating revenue adjustment deviate from**  
4 **historical experience?**

5 A. Pepco's adjustment appears to imply the company expects load growth and  
6 customer levels to remain flat. However, this assumption is contradicted by  
7 multiple sources. PJM's most recent forecasting projects 1.6 percent to 2.1 percent  
8 annual increases in summer and winter peak load, respectively.<sup>36</sup> The  
9 Commission's own electrification study projects Pepco's load to increase annually  
10 up to 1.2 percent, accounting for existing and mandated demand side reduction  
11 programs.<sup>37</sup> In short, Pepco's expectation that electricity sales will remain flat is  
12 unrealistic and insufficiently supported.

13 **Q. Do you propose any adjustments to the company's TTYCF operating**  
14 **revenue?**

15 A. Yes. I recommend an upwards adjustment to the TTYCF operating revenues of 2  
16 percent. This adjustment is consistent with PJM's most recent forecasting and  
17 reflects a more realistic operating revenues expectation.

18 **Q. What impact does this adjustment have on RMA 6?**

19 A. The impact of this adjustment on the TTYCF revenue requirement is \$11.7 million  
20 (net of taxes) and reflects growth from the end of the test year of September 30,

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<sup>36</sup> PJM Interconnection, LLC, *2026 PJM Load Forecast Report* at 21 (Jan. 14, 2026),  
<https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf>.

<sup>37</sup> Brattle, *An Assessment of Electrification Impacts on the Maryland Electric Grid* at 100 (Dec. 19, 2023),  
<https://www.psc.state.md.us/wp-content/uploads/Corrected-MDPSC-Electrification-Study-Report-2.pdf>

1 2025 for a full year thereafter. This adjustment has been reflected in Exhibit  
2 DMM-1 on Schedule C-6.

3 **C. Operation and Maintenance Expenses**

4 **Q. Do you propose any adjustments to the company's TTYCF operating and**  
5 **maintenance expenses?**

6 A. Yes. The following figure represents the trend in the company's actual and  
7 forecasted operating and maintenance expenses as compared to the company's 10-  
8 year average and clearly demonstrates that the O&M expenses in the TTYCF, and  
9 beyond, are unreasonable relative to recent trends. The forecasts in this figure  
10 include the TTYCF, Bridge Year, and FFTY.<sup>38</sup>

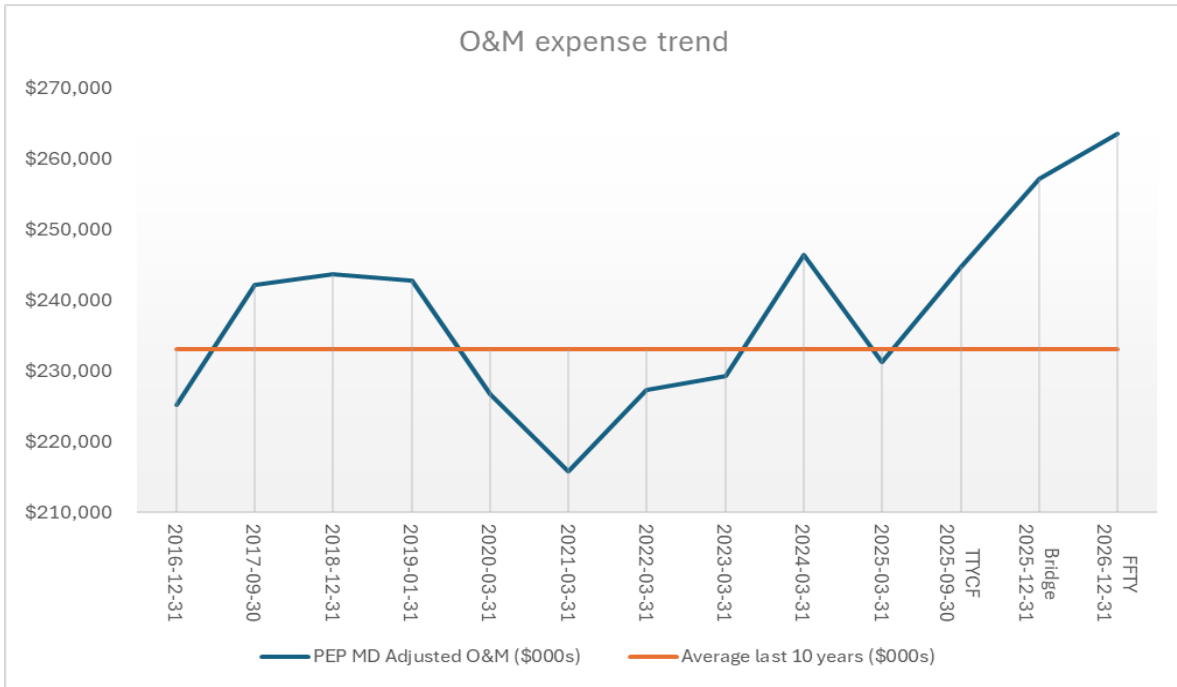
*Continued onto following page*

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<sup>38</sup> Information derived from Pepco response to OPC DR 6-7 Attachment Electronic Only.

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Figure 2 – Comparison of Pepco O&M Expenses



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As the figure above shows, the company’s O&M expenses are forecast to increase dramatically both in the TTYCF period and beyond. Focusing on the TTYCF, the forecast increase appears to largely unwind the savings that were achieved through to the end of March 31, 2025.

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I have reviewed the detailed O&M expenses. Based on my review, I propose adjustments to labor costs, non-labor O&M, deferred corrective maintenance work, rate case costs, and lobbying/advertisement expenses. I also recommend the Commission direct an update of rate case costs to the invoiced costs as of March 31, 2025, plus any reasonable forecast for the hearing.

1 **Q. Please explain the adjustment you propose to labor costs.**

2 A. The company's labor costs in the TTYCF estimate a forecast of 1,413 filled full-  
3 time equivalent positions, based on a total complement of staff of 1,453 and a  
4 vacancy rate of 2.75 percent.<sup>39</sup> Therefore, the company is basing its labor forecast  
5 for the Test Year on 1,413 positions. By comparison, actual full-time employees  
6 ("FTEs") at the end of 2024 were 1,299 and at the end of November 2025 were  
7 1,355.<sup>40</sup> The most current indication of actual labor costs is the 1,355 FTEs. Since  
8 this is the most accurate FTE forecast at this time, I recommend that the labor  
9 costs be calculated based on 1,355 FTEs.

10 Further, through RMA 20, the company is recommending labor cost  
11 escalation beyond the test year of 3.00% per year for management and union  
12 staff.<sup>41</sup> This level of increase follows the recent company-approved increases of  
13 3.00% for management and 4.00% for union staff.<sup>42</sup>

14 Over the longer-term—periods exceeding five-years or more— wages  
15 should increase at the rate of inflation. For example, as shown in Figure 2, the rate  
16 of inflation has slightly outpaced the rate of growth in hourly earnings since 2021.  
17 Additionally, while inflation will rise and drop over time, wage growth can be  
18 more stable:<sup>43</sup>

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<sup>39</sup> Pepco response to OPC DR 6-8 Attachment 1.

<sup>40</sup> *Id.*

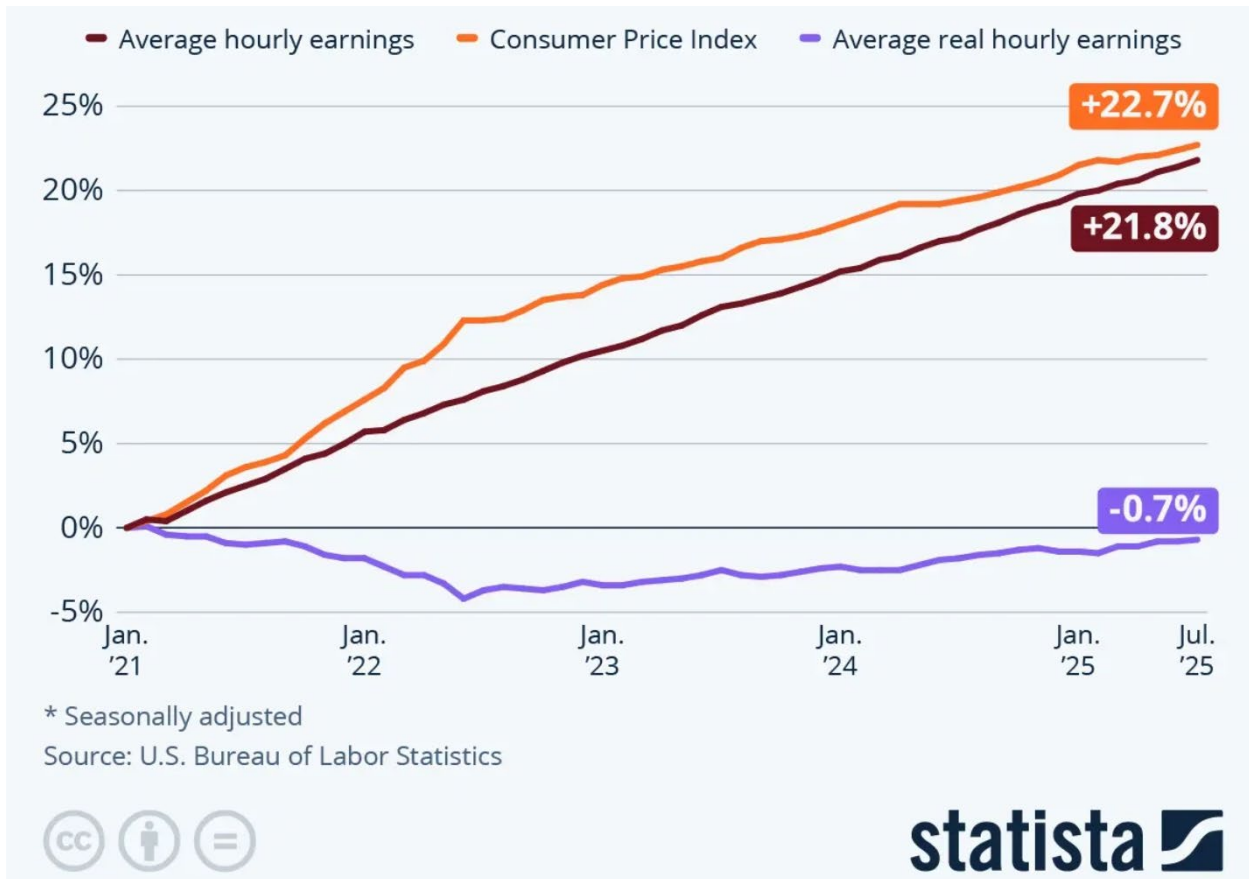
<sup>41</sup> Nelson Direct at 22:5-6.

<sup>42</sup> *Id.* at 21:9-11.

<sup>43</sup> Voronoi, *U.S. Wages Haven't Kept up With Inflation* (Sept. 4, 2025),  
<https://www.voroiapp.com/economy/US-Wages-Havent-Kept-Up-With-Inflation-6432>

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Figure 3 – Comparison of average hourly earnings to the Consumer Price Index



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For clarity, this does not mean that wage increases in each year will equal inflation in the year. This would be impractical as wage increases are forward looking while inflation is an after-the-fact determination. Nevertheless, wage increases are intended to provide compensation to employees that allow them to continue to maintain cost-of-living standards, which are directly impacted by inflation. Thus, over time salary increases will trend towards inflation. In summary, absent evidence to the contrary, it should be expected that salary growth in the long-term will trend towards the rate of inflation.

1           The company has provided insufficient evidence to demonstrate the  
2           reasonableness of labor cost increases beyond the test year should exceed the rate  
3           of inflation. For example, it is customary for a utility to provide compensation  
4           studies in support of its labor escalation rates where they are not contractually  
5           agreed to. This is particularly the case when the rate of escalation exceeds the rate  
6           of inflation. Yet, to my knowledge, Pepco has provided no studies to support its  
7           labor cost increases.

8           Accordingly, in addition to adjusting the level of FTEs, I have also updated  
9           the labor escalation rate. Because Pepco fails to justify increasing management  
10          salaries above the rate of inflation, I recommend a 2 percent labor escalation rate  
11          for management employees. The impact of this adjustment is reflected in the  
12          revised TTYCF RMA 2, as shown in Schedule C-20.

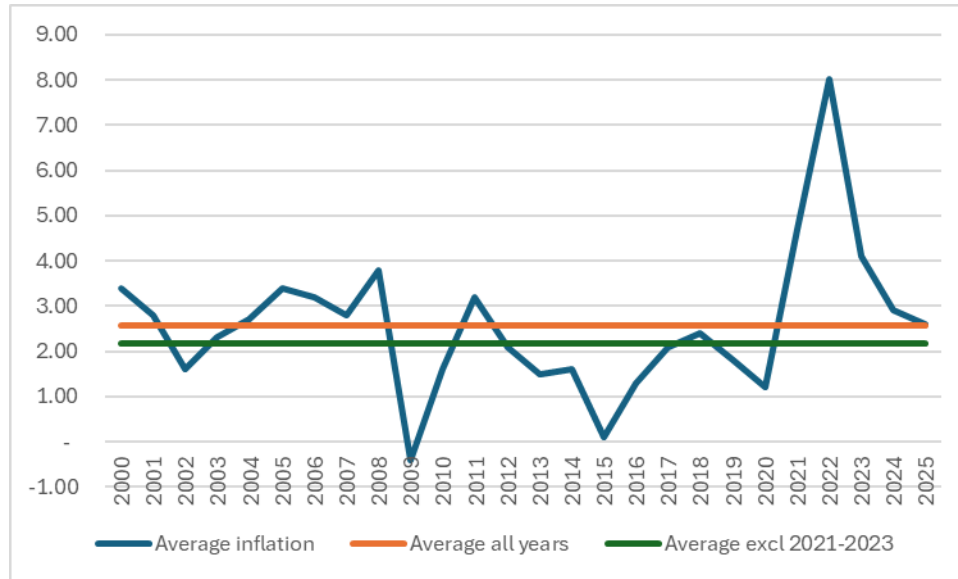
13   **Q.    Please explain the adjustment you propose to make to non-labor costs.**

14   A.    In RMA 25, Mr. Nelson adjusts Pepco's TTYCF to increase non-labor O&M  
15          expenses by 4.46% relative to the test year, which reflects the 2020–2025 Average  
16          Maryland CPI-U inflation rate. This historical inflation rate relied upon by the  
17          company, however, is not indicative of the future rate of inflation in 2025 and  
18          2026 for at least two reasons as discussed below.

19          First, the projected rate of inflation for Maryland for 2025 and 2026 is  
20          substantially less than the historic Maryland average for 2020—2025. Per the U.S.  
21          Bureau of Labor Statistics, the expected inflation rate for Maryland is

1 approximately 3.0 percent,<sup>44</sup> which is consistent with the broader U.S.; the  
2 inflation rate for 2026 is trending around 2.5 percent.<sup>45</sup> Additionally, the average  
3 rate of inflation from 2000 to 2025, excluding the anomalous period of 2021 to  
4 2023 is 2.17%, and including the anomalous period 2.57% as shown below:<sup>46</sup>

5 *Figure 4 – Trend in inflation from 2020 to 2025*



6  
7 Second, the inflation rate for 2020–2026 is impacted by the historically  
8 anomalous inflation experienced in 2021 and 2022.

9 Accordingly, I recommend adjusting Pepco’s non-labor O&M expenses to  
10 be based on a 2.5% inflation rate projected for Maryland in 2026. This adjustment

<sup>44</sup> Bureau of Labor Statistics, *Consumer Price Index, Baltimore-Columbia-Towson—December 2025* (Jan. 13, 2026), [https://www.bls.gov/regions/mid-atlantic/news-release/consumerpriceindex\\_baltimore.htm](https://www.bls.gov/regions/mid-atlantic/news-release/consumerpriceindex_baltimore.htm)

<sup>45</sup> Bd. of Gov. of the Fed. Reserve System, *Federal Open Market Committee: December 10, 2025: FOMC Projects materials, accessible version*, <https://www.federalreserve.gov/monetarypolicy/fomcproptab120251210.htm>

<sup>46</sup> U.S. Inflation Calculator, *Current US Inflation Rates: 2000–2026*, <https://www.usinflationcalculator.com/inflation/current-inflation-rates/>

1 better reflects the actual cost pressures the company is likely to face. The revenue  
2 requirement impact of my adjustment is set forth in Exhibit DMM-1, Schedule C-  
3 25.

4 **Q. Please explain the adjustment you propose for deferred corrective**  
5 **maintenance work.**

6 A. In her testimony, Pepco witness Elizabeth Morgan Downs O’Donnell states that  
7 “[t]he Company anticipates increases in emergent corrective repairs in 2025 due in  
8 part to actions taken in 2024, which is reflected in the year-over-year increases in  
9 O&M expense in future periods.”<sup>47</sup> In discovery, the company stated it had  
10 projected that emergent corrective repairs in 2024 would total \$33.4 million, but  
11 the company only spent \$27.8 million—a \$5.6 million decrease from the amount  
12 budgeted for 2024.<sup>48</sup> However, when asked in discovery to calculate the impact of  
13 this adjustment on the TTYCF, the company stated that such analysis had “not  
14 been performed on an individual action, project or program basis.”<sup>49</sup>

15 Ultimately, it appears that the company plans to complete work in 2025 that  
16 it previously deferred from 2024, along with other anticipated corrective emergent  
17 maintenance work. Given that the company’s 2024 rates were based on forecasts  
18 that included work for emergent corrective repairs, I consider it inappropriate for  
19 the company to defer work that was previously expected for 2024 to future years.

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<sup>47</sup> Direct Testimony of Elizabeth Morgan Downs O’ Donnell (“O’Donnell Direct”) at 25:12-4.

<sup>48</sup> Pepco response to OPC DR 6-12 (\$33.4 million - \$27.8 million).

<sup>49</sup> *Id.*

1 This effectively means that customers are being charged twice for the same work:  
2 first as part of the rates authorized in Case No. 9702, and again through the rates  
3 that would be authorized in this proceeding.

4 **Q. Did the company’s deferral of work in 2024 and 2025 impact its reliability**  
5 **performance?**

6 A. No. As shown by Figure 5, deferring the work from 2024 to future years has not  
7 triggered an obvious decline in the company’s reliability for 2024. If anything, the  
8 company’s reliability metrics, as shown below, are very strong and improving:<sup>50</sup>

9 *Figure 5 – Trend in company reported reliability metrics*

Actual vs Forecasted Reliability				
	Actual		Forecasted (See Reliability Standards Reports)	
Year	SAIFI	SAIDI	SAIFI	SAIDI
2020	0.65	54	0.76	77
2021	0.58	55	0.74	71
2022	0.68	56	0.73	68
2023	0.52	46	0.71	65
2024	0.52	48	0.66	61
2025	-	-	0.59	57
2026	-	-	0.55	55

10

11 Moreover, considering the decision the company made in 2024 to defer select  
12 corrective maintenance work, it is apparent that the utility has a fair amount of  
13 discretion in terms of the timing of this work.

14 For all these reasons, I recommend that the Commission remove all of the  
15 \$5.6 million in deferred corrective maintenance work deferred in 2024. The result  
16 of this adjustment is a reduction to both the TTYCF and FFTY forecast of \$5.6

<sup>50</sup> Pepco response to OPC DR 6-36.

1 million. Regarding the FFTY forecast, as the company has not clearly stated where  
2 the deferred corrective maintenance work has been deferred to, I consider it  
3 appropriate to reduce the budgeted costs in the projected test year. The specific  
4 TTYCF adjustment is reflected in the updated RMA No. 25, which is reflected in  
5 Exhibit DMM-1 Schedule C-25.

6 **Q. What adjustment do you recommend to rate case costs?**

7 A. I recommend the Commission disallow Pepco's requested recovery of rate case  
8 expense in this case. The company's filing for a stated rate is atypically  
9 complex—consisting of four different revenue requirements as well as two  
10 external studies it commissioned to justify increasing spending. The scope and  
11 complexity of Pepco's application fall well outside what is reasonable to recover  
12 from customers.

13 Ordinarily, I may have recommended only the exclusion of rate case  
14 expenses incurred by the company that are atypical to a standard application for a  
15 rate increase, such as Pepco's proposal to use a non-standard revenue requirement  
16 and costs associated with studies prepared by Brattle and NERA. In discovery, I  
17 asked Pepco to quantify costs specific to preparing the FFTY, which Pepco did not  
18 provide.<sup>51</sup> While I maintain that complete disallowance of rate case expense is  
19 appropriate in this case. If the Commission disagrees with my recommendation, I  
20 propose that Pepco's rate case recovery exclude the incremental costs incurred for

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<sup>51</sup> Pepco Response to OPC DR 8-3.

1 preparing this filing relative to the preparation of the TTYCF revenue requirement.

2 The specific adjustment is reflected in the updated RMA No. 10, which is

3 reflected in Exhibit DMM-1 Schedule C-10.

4 **Q. What adjustment do you recommend to lobbying and advertisement**  
5 **expenses?**

6 A. The company “identified approximately \$29 thousand allocated from [Exelon  
7 Business Services Company] that had been inadvertently recorded to FERC 923  
8 and included in the cost of service” related to management of employee volunteer  
9 programs, charitable giving programs, sponsorships, and other programs.<sup>52</sup> The  
10 company also confirmed that it “does not separately track the costs of internal  
11 employee time spent developing and approving these [marketing] campaigns”<sup>53</sup>

12 All costs associated with lobbying, advertisement expenses, and other costs  
13 that are not permitted to be included in rates should be excluded from recovery.  
14 This includes not only the external charges of vendors retained by the company,  
15 but also all slivers of time incurred by the Pepco’s employees. Regardless of  
16 whether the position is required to provide safe and reliable service or not, if that  
17 position performs work that supports activities that Pepco considers to be below  
18 the line, the cost of such supporting work should be approximated and removed  
19 from the revenue requirement.

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<sup>52</sup> Pepco response to OPC DR 17-6.

<sup>53</sup> Pepco response to OPC DR 17-8.

1           Accordingly, I recommend the Commission direct Pepco to identify and  
2 perform a detailed quantification, at its own cost, of all internal charges it has  
3 incurred to support below-the-line activities and to remove those costs from the  
4 revenue requirement. This includes the \$29 thousand error noted above. The  
5 specific adjustment is reflected in the updated RMA No. 29, which is reflected in  
6 Exhibit DMM-1 Schedule C-29.

7           **D. Depreciation and Amortization Expense**

8 **Q. Do you propose any adjustments to the company's TTYCF depreciation and**  
9 **amortization expense?**

10 A. The only adjustments I propose at this time are consequential adjustments to  
11 reflect the reduction in rate base included in TTYCF RMA 3 and 4. The change in  
12 depreciation and amortization expense is also shown in RMA 3 and 4 in Exhibit  
13 DMM-1 on Schedule C-3 and C-4, respectively. I have also adjusted for the  
14 disallowances in Schedule C-1 discussed above.

15           **E. Income and Other Taxes**

16 **Q. Do you propose any adjustments to the company's TTYCF income and other**  
17 **taxes?**

18 A. I recommend consequential adjustments to income taxes that reflect the other  
19 changes I have modeled to the TTYCF revenue requirement. I also recommend  
20 consequential adjustments to the property tax expense resulting from my  
21 recommended reductions to rate base.

22           I have also adjusted property tax expense to reflect the rate base  
23 adjustments I noted above on a pro-rata basis. This adjustment is appropriate as it

1 reflects a reduced level of property taxes commensurate with the lower level of  
2 investment included in rate base. The adjustment is shown in TTYCF RMA 27,  
3 included in Exhibit DMM-1 on Schedule C-27.

4 **Q. Did the company include an adjustment related to the normalization of net**  
5 **operating loss carryforwards?**

6 A. Yes. Pepco states that it was proposing an adjustment to reduce accumulated  
7 deferred income taxes (“ADIT”) related to NOLCs, as well as its regulatory tax  
8 liability to comply with the “normalization” provisions under federal tax law.<sup>54</sup>

9 **Q. What is “normalization” and how it relates to net operating losses?**

10 A. “Normalization” refers to the process by which the near-term benefit to utilities  
11 from accelerated depreciation is passed on to customers over the remaining useful  
12 life of the asset in the form of reduced rates.<sup>55</sup> When a utility claims accelerated  
13 depreciation for a capital asset, the remaining tax liability is reflected in the  
14 balance of accumulated deferred income taxes (“ADIT”). The utility’s ADIT  
15 balance is considered “cost free capital” and is deducted from rate base. A lower  
16 ADIT balance results in a higher rate base amount.

17 A net operating loss carryforward (“NOLC”) refers to a utility’s decision to  
18 apply a claimed net operating loss to reduce taxable income in a future year. For  
19 utilities that are a member of an affiliated group of corporations—like Pepco is to  
20 Exelon—the parent company can leverage its subsidiaries net operating losses to

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<sup>54</sup> Leming Direct II at 15:15-17.

<sup>55</sup> *Id.* at 16:15-21.

1 offset the parent's overall tax liability. Typically, the parent compensates the  
2 subsidiary in cash equal to the tax benefit attributable to the use of the subsidiary's  
3 net operating loss. Under the normalization rules, for ratemaking purposes only  
4 the utility is required to reflect the utilization of tax NOLCs when it has separate  
5 company taxable income, irrespective of the income of the consolidated group.  
6 This interaction effectively creates incremental deferred tax assets related to the  
7 recalculated NOLCs which reduce the ADIT balance. In the case of the company  
8 the reduction is \$3 million.<sup>56</sup>

9 **Q. Please explain the company's adjustment.**

10 A. Pepco's adjustment reflects a change in how it accounts for net operating loss  
11 carryforwards used by the parent company to reduce its tax liability. Based on an  
12 IRS Private Letter Ruling issued to a wholly separate utility; Pepco proposes to  
13 use a new methodology for accounting for NOLCs. Under this methodology the  
14 company recalculates its deferred tax assets pertaining to NOLCs as well as the  
15 impact on the company's excess deferred income tax ("EDIT") regulatory  
16 liability. As explained by the company, "EDIT represents the difference between  
17 the ADIT at the prior federal corporate tax rate of 35% and the new tax rate of  
18 21%."<sup>57</sup> The effect of this change results in a significant reduction in the utility's  
19 ADIT and EDIT regulatory liability balances,<sup>58</sup> and a corresponding increase in

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<sup>56</sup> *Id.* at 20:14-16.

<sup>57</sup> *Id.* at 21:1-2.

<sup>58</sup> Pepco response to OPC DR 6-40(c) Attachment Confidential

1 rate base. In discovery, Pepco states that this change increases rate base by \$51.5  
2 million, and accounts for \$7.4 million of Pepco's proposed TTYCF revenue  
3 requirement.<sup>59</sup>

4 **Q. Is Pepco's adjustment necessary?**

5 A. No. Pepco's claims that it is required to initiate this change based on the IRS  
6 Private Letter ("PLR") rulings issued to another utility operating in an entirely  
7 different jurisdiction under the oversight of an entirely different regulatory body.  
8 The very same IRS guidance Pepco relies on expressly forbids any party, except  
9 for the taxpayer to whom the ruling is directed, from relying on the ruling's  
10 findings. Under Section 6110(k)(3) of the Internal Revenue Code, a PLR may not  
11 be used or cited as precedent by anyone other than the requesting taxpayer.

12 In other words, only the party requesting the PLR can expressly rely on it.  
13 Pepco points to no Commission precedent that holds otherwise.

14 **Q. Didn't Pepco file its own Private Letter Ruling request?**

15 A. Yes. In discovery, the company confirmed that it had submitted a PLR to the IRS  
16 seeking guidance on whether its accounting practices for net operating loss  
17 carryforwards comply with the normalization rules.<sup>60</sup> Pepco also confirmed that  
18 the IRS has yet to issue a ruling.<sup>61</sup>

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<sup>59</sup> Pepco Response to OPC DR 6-40(e) Attachment. These numbers reflect Pepco's initial TTYCF filing and do not reflect the update to actuals. I will update these numbers in my surrebuttal after receiving Pepco discovery responses that update the answers to OPC DR 6-40(e).

<sup>60</sup> Leming Direct II at 14:8-15.

<sup>61</sup> Pepco response to OPC DR 6-40(a).

1 **Q. Please explain why this adjustment should be denied by the Commission.**

2 A. Until a PLR is received by the company, it would be inappropriate to reflect  
3 Pepco's proposed change in tax treatment from a regulatory perspective.

4 Approving this change would result in customers being charged  
5 prematurely for a change in tax accounting that Pepco is not required to implement  
6 at this time. The IRS has not deemed Pepco's current tax accounting practices out  
7 of compliance with the normalization rules. Accordingly, Pepco should not be  
8 authorized to recover additional costs from customers based on the mere  
9 speculation of how the IRS may rule on the company's requests.

10 **Q. Isn't there a risk that, if Pepco's change is not approved, the IRS may**  
11 **penalize the company for violating the normalization rules?**

12 A. As Mr. Leming's testimony notes, a finding of a normalization violation "results  
13 in the loss of a right to claim accelerated tax depreciation on assets in service as of  
14 the date of the violation, and any future asset additions."<sup>62</sup> This would directly  
15 increase customer costs, and I acknowledge the seriousness of such finding.

16 However, if the Commission were to reject Pepco's proposed adjustment,  
17 the company's risk of being found to violate the normalization rules while its  
18 company's PLR request is pending is extremely low.

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<sup>62</sup> Leming Direct II at 17:1-3.

1 **Q. Why is the risk of a normalization violation extremely low?**

2 A. The IRS established a Safe Harbor for inadvertent or unintentional violations of  
3 the normalization rules.<sup>63</sup> The Safe Harbor requires a utility to correct any  
4 accounting practices inconsistent with the normalization rules at the “next  
5 available opportunity.”<sup>64</sup> For a taxpayer without a rate proceeding, the next  
6 available opportunity means “the next rate proceeding.”<sup>65</sup> However, if, at the  
7 conclusion of that rate proceeding, the taxpayer has a private letter ruling request  
8 pending before the IRS, the utility would not be subject to a normalization  
9 violation if any rates authorized by the regulator are subject to adjustment at a later  
10 date in order to conform to the IRS’s ruling.<sup>66</sup> In other words, the Commission  
11 could set rates that exclude Pepco’s requested NOLC adjustment that are subject  
12 to adjustment based on the outcome of Pepco’s pending PLR letter request. In  
13 such a circumstance, the company would fall under the protection of the Safe  
14 Harbor and not be at any risk of a normalization violation.

15 **Q. What is your recommended treatment of Pepco’s proposed NOLC**  
16 **adjustment?**

17 A. I recommend the Commission remove the adjustment from Pepco’s TTYCF  
18 revenue requirement. The company states that its adjustment increases rate base by

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<sup>63</sup> Rev. Proc. 2017-47.

<sup>64</sup> *Id.* § 5.01.

<sup>65</sup> *Id.* § 4.07(1).

<sup>66</sup> *Id.* § 4.07(3).

1       \$51.5 million.<sup>67</sup> This adjustment is reflected as TTYCF RMA 28, included in  
2       Exhibit DMM-1 on Schedule C-39.

3               I also recommend that the Commission require the company to notify the  
4       Commission upon the issuance a ruling on the company's PLR request and, if the  
5       IRS finds Pepco's prior accounting practices to be inconsistent with the  
6       normalization rules, require the company to propose an adjustment to the revenue  
7       requirement to conform the company's tax accounting practices to the IRS's  
8       normalization rules.

9       **F. Operating Income**

10    **Q. Do you propose any adjustments to the company's TTYCF operating**  
11    **income?**

12    A. Yes. I have adjusted the company's TTYCF required operating income to reflect  
13    the rate of return recommendation contained in the Direct Testimony of OPC  
14    Witness Garrett.

15    **V. Determination of FFTY Revenue Requirement**

16    **Q. Please summarize this section of your testimony.**

17    A. My primary recommendation is for the Commission to deny Pepco's proposed  
18    FFTY. However, if the Commission disagrees with my recommendation, I have  
19    calculated a revised FFTY that reduces Pepco's currently effective revenue

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<sup>67</sup> Pepco Response to OPC DR 6-40(e) Attachment. These numbers reflect Pepco's initial TTYCF filing and do not reflect the update to actuals. I will update these numbers in my surrebuttal upon receiving update responses to OPC DR 6-40(e) from the company.

1 requirement by \$2.5 million for the Commission to consider. As will be explained  
2 below, this revenue requirement reflects adjustments to rate base, O&M expense,  
3 operating income, and cost of capital. My revenue requirement calculations are set  
4 forth in Exhibit DMM-2, on Schedule A.

5 **A. Rate Base**

6 **Q. Do you include any adjustments to the company's FFTY rate base?**

7 A. Yes. My proposed FFTY revenue requirement reflects the capital project  
8 disallowances recommended by OPC witness Fitzhenry.<sup>68</sup> These adjustments are  
9 reflected on Schedule C-27 in Exhibit DMM-2 and reduce rate base by \$95.937  
10 million.

11 **B. Operating Revenues**

12 **Q. What is the company's forecasted operating revenue for the FFTY?**

13 A. The company's FFTY operating revenues reflect a series of adjustments to the  
14 historical test year ("HTY") (12 months ending December 31, 2024) and bridge  
15 year (12 months ending December 31, 2025). The HTY includes a \$21.84 million  
16 adjustment to annualize revenues from electricity sales to reflect those approved in  
17 Case No. 9702. This reflects an increase over the test year of 2.7 percent to  
18 operating revenues.<sup>69</sup> For the bridge year and FFTY, the company made a further  
19 upward adjustments to electricity sales of \$0.125 million and \$0.119 million

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<sup>68</sup> Fitzhenry Direct at 40, Table CTF-4.

<sup>69</sup> Leming Direct II, Schedule (RTL)-1.

1           respectively.<sup>70</sup> In short, from 2024 through 2026, the total growth in operating  
2           revenues is \$23.977 million (\$819.115 million - \$795.138 million), or 3.0%,  
3           which averages out to just 1.0% per year. But from 2025 to 2026, the company  
4           projects a decrease in operating revenues.

5   **Q.    Is the proposed level of operating revenues in the FTY reasonable?**

6   A.    No. As I noted earlier in my discussion of Pepco's adjustment related to its  
7           TTYCF operating revenues, this proposal is unreasonable and inconsistent with  
8           numerous load forecasts, that each project load growth ranging up to 2 percent.

9   **Q.    Do you propose any adjustments to the company's FTY operating revenue?**

10 A.    Yes. I have reflected an increase in FTY operating revenues of 1 percent per year  
11           (including in the bridge year) as FTY RMA 25 in Exhibit DMM-2 on Schedule  
12           C-25. I have reflected the adjustment on a compounding basis.

13   **C.    Operation and Maintenance Expenses**

14 **Q.    Do you propose any adjustments to the company's FTY operating and**  
15 **maintenance expenses?**

16 A.    Yes. As noted earlier in my discussion of O&M expenses in the context of the  
17           TTYCF revenue requirement, many of Pepco's projected O&M expenses are  
18           unsupported by the evidence and are excessive.

19           I have reviewed the detailed O&M expenses and based on that review I  
20           propose adjustments to proposed budgets for labor costs, maintenance of overhead  
21           lines (FERC Account 593), and outside services employed (FERC Account 923),

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<sup>70</sup> *Id.*

1 deferred corrective maintenance work, rate case expenses, and costs incurred by  
2 the company relating to lobbying and advertising activities that are reflected  
3 below-the-line. I also recommend the Commission direct removal of all rate case  
4 costs included in the projected test year.

5 **Q. Please explain the adjustment you propose to labor costs.**

6 A. The company's labor costs in the FFTY reflect a total complement of staff of  
7 1,453, adjusted for a vacancy of 2.75 percent for an FTE forecast of 1,413  
8 positions.<sup>71</sup> Therefore, the company is basing its labor forecast for the FFTY on  
9 1,413 positions. By comparison, actual FTEs at the end of 2024 were 1,299 and at  
10 the end of November 2025 were 1,355.<sup>72</sup> The most current indication of actual  
11 labor costs is the 1,355 FTEs. As this is the most accurate FTE forecast at this  
12 time, I recommend that the labor costs be calculated based on 1,355 FTEs.

13 Furthermore, for the same reasons discussed above with respect to the  
14 TTYCF, I do not consider the FFTY forecast of labor escalation to be reasonable.  
15 Accordingly, in addition to adjusting the level of FTEs I have also updated the  
16 FFTY labor escalation rate to 2 percent, consistent with my proposed adjustment  
17 to the TTYCF. The impact of these adjustments is reflected in the revised FFTY  
18 RMA 26 as Schedule C-26 in Exhibit DMM-2.

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<sup>71</sup> Pepco response to OPC DR 6-8 Attachment 1.

<sup>72</sup> *Id.*

1 **Q. Does Pepco's FFTY include an increase in spending on the maintenance of**  
2 **overhead lines (FERC Account 593)?**

3 A. Yes. Pepco's FFTY projects \$81.4 million in spending on maintenance of  
4 overhead lines, which is an increase from 2024 of \$9.7 million.<sup>73</sup> Such costs  
5 largely relate to vegetation management and the general maintenance of overhead  
6 lines.

7 **Q. Does Pepco provide any justification for this cost increase?**

8 A. Yes. Much of the increase appears to be increases in storm restoration, deferred  
9 corrective maintenance, and vegetation management cost increases.<sup>74</sup>

10 **Q. Please explain the adjustment you propose to make to maintenance of**  
11 **overhead lines (FERC Account 593).**

12 A. Pepco's FFTY reflects significant increase in overhead line maintenance costs  
13 from 2024 to 2026:<sup>75</sup>

*Continued onto following page*

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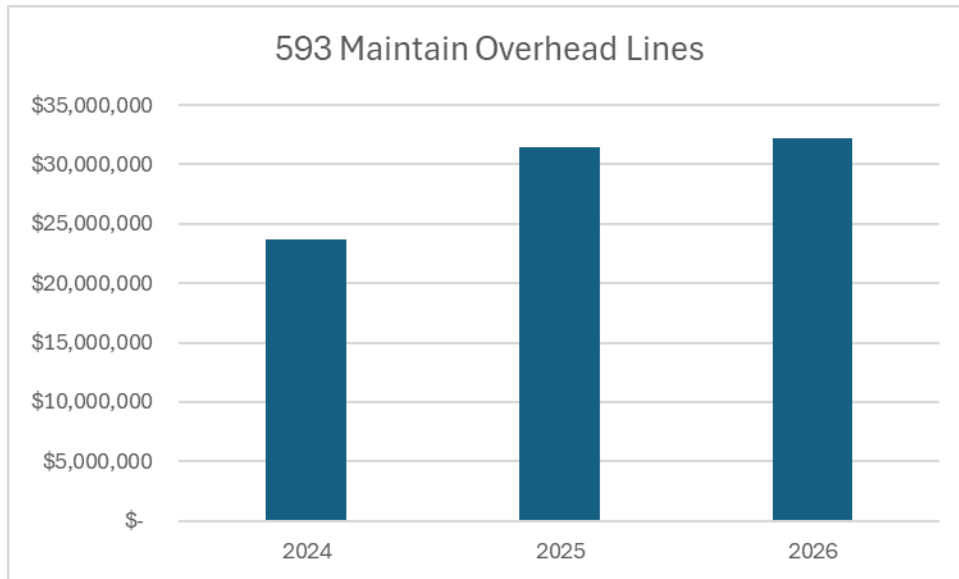
<sup>73</sup> Information obtained from General Filing Req II.A.2 Attachment M-O&M Exp Electronic Only.

<sup>74</sup> Direct Testimony of Samuel Williams ("Williams Direct"), Schedule (SW)-1 at 16.

<sup>75</sup> Information obtained from General Filing Req II.A.2 Attachment M-O&M Exp Electronic Only.

1

*Figure 6 – Trend in costs in Account 593 from 2024 to 2026*



2

3 As shown above in Figure 5, the company is proposing a material increase  
4 in costs in the projected test year for this account relative to the 2024 test year. As  
5 already explained earlier, the company’s performance is in the top quartile of its  
6 comparators, and the highest in Maryland.

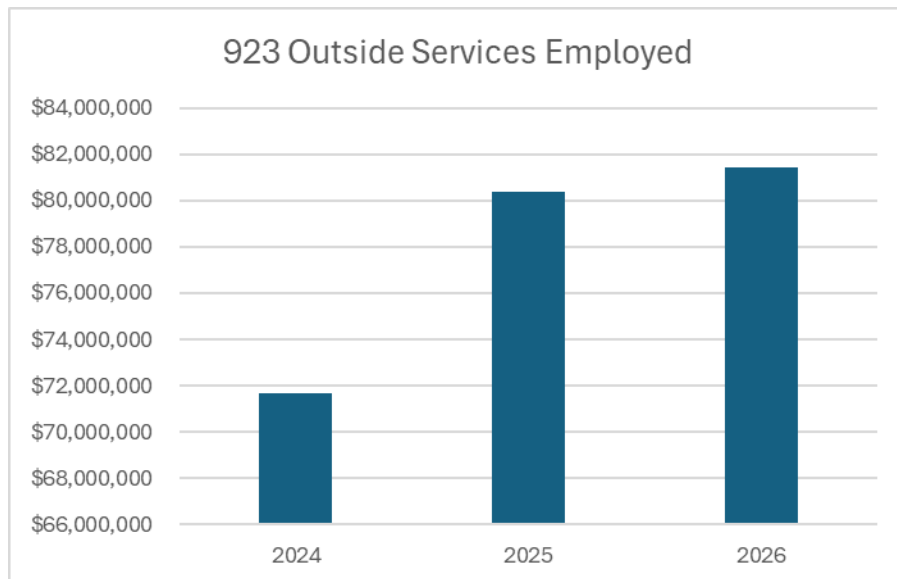
7 I have reviewed the company’s testimony supporting this increase and  
8 consider the increase to be unjustified and unwarranted on the basis that the  
9 planned improvements around reliability are unnecessary and frankly cost  
10 prohibitive.

11 For this reason, I recommend the Commission set the level of expense in  
12 this account at the 2024 test year level of \$23.683 million, which is a reduction for  
13 2026 of \$8.550 million. The adjustment is reflected on FFTY RMA 26, which is  
14 included in Exhibit DMM-2 on Schedule C-26.

1 **Q. Does Pepco’s FFTY include a proposed increase in spending charged to**  
2 **FERC Account 923, Outside Services Employed?**

3 A. Yes. Outside Services Employed—recorded to FERC Account 923—consists  
4 primarily of billings to Pepco from the PHI and Exelon business service  
5 companies. As shown in the figure below, charges to FERC Account 923  
6 increased from 2024 to 2025 by approximately 12.3 percent; in 2026, charges in  
7 Account 923 increased by an additional 1.3 percent:<sup>76</sup>

8 *Figure 7 – Trend in costs in Account 923 from 2024 to 2026*



9  
10 **Q. What explanation does the company provide for this cost increase?**

11 A. Pepco witness O’Donnell explains that the “Outside Services costs recorded under  
12 FERC Account 923 primarily reflect allocations from shared service entities,  
13 namely, Exelon Business Service Company (BSC) and PHISCO.”<sup>77</sup> According to

<sup>76</sup> Information obtained from General Filing Req II.A.2 Attachment M-O&M Exp Electronic Only.

<sup>77</sup> O’Donnell Direct at 24:5-7.

1 Witness O’Donnell, because these costs are allocated to Pepco from its parent  
2 companies, “any meaningful reduction in these costs would require changes at the  
3 enterprise level, that Pepco does not have direct control of and would require input  
4 and coordination across all Exelon affiliates.”<sup>78</sup> The proposed increase in spending  
5 appears to be largely in response to the disallowance of similar costs by the  
6 Commission in Case No. 9702.<sup>79</sup> The company states that “because Pepco could  
7 not directly reduce its allocated service company costs, it took actions defer  
8 planned work that reduced spending in operational areas . . . .”<sup>80</sup> The sharp  
9 increase in outside services costs for 2025 and 2026 is tied to the company’s plans  
10 to address work it deferred in 2024.

11 **Q. Please explain the adjustment you propose to Outside Services Employed**  
12 **(USA 923).**

13 A. Having reviewed Pepco’s explanation for the increase in outside services costs, I  
14 conclude that Pepco is simply seeking to adjust for the \$13.2 million reduction to  
15 this account previously directed by the Commission.<sup>81</sup> The company provides no  
16 new evidence of a demonstrable need for these costs—beyond merely correcting  
17 for the reduced O&M budget the Commission authorized in Case No. 9702.

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<sup>78</sup> *Id.* at 24:15-17.

<sup>79</sup> *Id.* at 23:3-5.

<sup>80</sup> *Id.* at 25:7-10.

<sup>81</sup> *Id.* at 23:3-5.

1           Moreover, the FFTY adjustment appears to be an attempt to pass through  
2           increasing costs imposed by Pepco's parent companies, over which the  
3           Commission has less direct oversight.

4                     Absent further evidence demonstrating a need and corresponding customer  
5           benefits from increased outside services costs, I do not see any reason for the  
6           Commission to deviate from the scrutinizing approach it took to these costs in  
7           Case No. 9702. I recommend the cost be set at the 2024 historical year of \$71.675  
8           million. This reflects a reduction in FFTY O&M spending of \$9.738 million.  
9           Given the lack of evidence regarding the reasonableness of the charges, I do not  
10          recommend any adjustment to the outside services spending level reflected in the  
11          historic test year. The adjustment is reflected on FFTY RMA 26, which is  
12          included in Exhibit DMM-2 on Schedule C-26.

13   **Q.    Please explain the company's proposed increase in corrective maintenance**  
14   **spending.**

15   A.    Like the TTYCF, the company's FFTY includes an increase in O&M expense  
16          from 2024 to 2026 that "reflects the increases in emergent corrective repairs due to  
17          the deferrals from 2024."<sup>82</sup> The company states, without supporting evidence, that  
18          the increase spending is necessary to avoid "risking service reliability and  
19          safety."<sup>83</sup>

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<sup>82</sup> O'Donnell Direct at 26:4-6.

<sup>83</sup> *Id.* at 26:3-4.

1 **Q. Please explain the adjustment you propose to deferred corrective**  
2 **maintenance work.**

3 A. The adjustment I recommend in relation to corrective maintenance work is  
4 consistent with the adjustment I recommend for the TTYCF. The Commission  
5 should remove 2024 deferred corrective maintenance work costs of \$5.6 million  
6 from the FFTY. The work that is included in the forecast to be completed in 2024  
7 should have been completed in 2024, and the deferral of that work by the company  
8 appears to be unsupported as discussed earlier. The specific adjustment is reflected  
9 in the updated FFTY RMA No. 26, which is reflected in Exhibit DMM-2 Schedule  
10 C-26.

11 **Q. What adjustment do you recommend to rate case costs?**

12 A. For the same reasons stated above in Section IV.C regarding the TTYCF, I  
13 recommend that all of the forecast rate case costs be removed. The impact of these  
14 adjustments is reflected in the revised FFTY RMA 26 as Schedule C-26 in Exhibit  
15 DMM-2.

16 **Q. What adjustment do you recommend to lobbying and advertisement**  
17 **expenses?**

18 A. For the same reasons stated above in Section IV.C for the TTYCF lobbying,  
19 advertisement and related expenses of an unregulated nature, I recommend the  
20 Commission direct the removal of all internal and external costs incurred by the  
21 company and the error of \$29 thousand identified earlier from the FFTY forecast.

1 The impact of these adjustments is reflected in the revised FFTY RMA 26 in  
2 Schedule C-26 in Exhibit DMM-2.

3 **D. Depreciation and amortization expense**

4 **Q. Do you propose any adjustments to the company's FFTY depreciation and**  
5 **amortization expense?**

6 A. The only adjustments I propose at this time are consequential adjustments to  
7 reflect the reduction in rate base resulting from the adjustments discussed above.

8 The change in depreciation and amortization expense is also shown in RMA 27  
9 Exhibit DMM-2 on Schedule C-27.

10 **E. Income and Other Taxes**

11 **Q. Do you propose any adjustments to the company's FFTY income and other**  
12 **taxes?**

13 A. I recommend consequential adjustments to income taxes that reflect the other  
14 changes I have modeled to the FFTY revenue requirement.

15 I have also adjusted property tax expense to reflect the rate base  
16 adjustments I noted above on a pro-rata basis. This adjustment is appropriate as it  
17 reflects a reduced level of property taxes commensurate with the lower level of  
18 investment included in rate base. The adjustment is shown in FFTY RMA 28,  
19 included in Exhibit DMM-2 on Schedule C-28.

20 **Q. Does the company's FFTY also include an adjustment related to a proposed**  
21 **change in the accounting treatment for net operating loss carryforwards**

22 A. Yes. Like the TTYCF, Pepco's FFTY also includes an adjustment to reflect a  
23 change in accounting for NOLCs. I discussed this adjustment in detail earlier in

1 my testimony. I recommend removing the impact of the company's proposed  
2 change.

3 **Q. What is your recommended treatment of Pepco's proposed NOLC**  
4 **adjustment?**

5 A. I recommend the Commission remove the adjustment from Pepco's FPTY and  
6 TTYCF revenue requirement. The company stated that its adjustment reduces  
7 ADIT by \$3 million<sup>84</sup> and the regulatory liability related to excess deferred  
8 income taxes by \$39.4 million.<sup>85</sup> This adjustment is reflected as FPTY RMA 28,  
9 included in Exhibit DMM-2 on Schedule C-28.

10 I also recommend that the Commission require the company to notify the  
11 Commission upon the issuance a ruling on the company's PLR request and, if the  
12 IRS finds Pepco's prior accounting practices to be inconsistent with the  
13 normalization rules, require the company to propose an adjustment to the revenue  
14 requirement to conform the company's tax accounting practices to the IRS's  
15 normalization rules.

16 **F. Operating Income**

17 **Q. Do you propose any adjustments to the company's FPTY operating income?**

18 A. Yes. I have adjusted the company's FPTY required operating income to reflect the  
19 rate of return recommendation contained in the Direct Testimony of OPC Witness  
20 Garrett.

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<sup>84</sup> Leming Direct II at 20:14-16.

<sup>85</sup> *Id.* at 21:4-5.

1      **VI. Conclusion.**

2      **Q. Does this conclude your Direct Testimony?**

3      **A. Yes.**

**WORK EXPERIENCE**

**Accounting, Finance, Tax and Regulatory Consultant** January 2016 – Present  
Emrydia Consulting Corporation (owner)

- Preparation of evidence and expert testimony both written and oral on a variety of areas, including cost-of-service, revenue requirement, income tax, valuation, depreciation, and cost of capital. Some examples of oral testimony include:
- Preparation of comprehensive cost-of-service studies.
- Preparation of business and succession plans.
- Completion of business valuations, including the determination of both fair market value and replacement cost new less depreciation, as well as other valuations for utilities.
- Provided advice on numerous matters including cost-of-service rate design, business issues, hedging, and other specific matters.

**Business Valuation and Accounting/Regulatory Risk Consultant** Nov 2015 – January 2016  
Berkshire Hathaway Energy Canada

- Advised senior management at Berkshire Hathaway Energy Canada on potential acquisition risks and rewards.
- Evaluated all financial, treasury, regulatory, operational, and legal elements of potential acquisitions and coordinate with other senior team members to develop a go/no-go proposal for each potential acquisition.
- Constructed and maintained a business valuation model to support calculations of the enterprise value, including development of assumptions around levered/unlevered discount rates, cash flows, terminal values and certain tax assumptions depending upon the ultimate structure of the transaction.

**Regulatory Specialist (Consultant)** November 2012 – July 2015  
AltaLink L.P.

- Drafted or coordinated the drafting of AltaLink's 2012/2013 Deferral Account Application and 2015/2016 GTA, including responses to information requests, updates to the applications and other matters as required.
- Assisted AltaLink, working in conjunction with other Alberta utilities, in the drafting of the 2013 GCOC R&V application and the Utility Asset Disposition (UAD) Appeal. This work included detailed research and analysis into GCOC and UAD matters.
- Actively engaged in the AUC proceeding to assess the AltaLink sale, including responses to information requests and responding to due diligence questions from the sale itself.
- Prepared AltaLink's 2011, 2012, 2013 and 2014 Reports on Operations and Finances in compliance with AUC Rule 005.
- Assisted in the coordination of the 2013/2014 GTA oral hearing, including undertakings, preparation of cross-examination questions and monitoring of oral testimony.
- Prepared the public and confidential rebuttal evidence, responses to additional information requests, and argument/reply argument for the 2013/2014 GTA.
- Acted as AltaLink's lead representative on a variety of key applications filed by other Alberta Utilities, including PBR applications, GCOC, capital tracker applications, GTAs, Deferral Account Applications, and also the AESO's Tariff Application.
- Automated the majority of the Report on Operations model and improved the documentation related to the process, thereby reducing the time required to update the Report on Operations to a matter of a couple weeks rather than a couple months.

- Automated and refined the Hearing Cost and Legal Cost process, including filing of costs with the AUC, reconciliation of costs for accounting purposes, and installation of an improved internal information system for gathering and reporting.
- Continued monitoring of other proceedings and performed all other duties as required by the Vice President, Regulatory Rates and Tariffs.

**Manager, Financial Reporting (Contract)**

April 2012 – October 2012

AltaLink L.P.

- Managed the Financial Reporting group, and performed all duties as required of the Manager, Financial Reporting and any other duties as required.
- Coordinated the implementation of BPC to assist with the consolidation of financial results in SAP.
- Provided technical IFRS input for a variety of projects and Canadian Electricity Association matters.

**Consultant, Corporate Finance and Tax**

February 2012 – April 2012

Enerflex Ltd.

- Assisted with pre-implementation planning for IFRS 9 through 13.
- Reviewed the hedging policy in place at Enerflex to assess ongoing effectiveness and provided feedback on a new treasury management system.
- Reviewed annual financial statements, Management's Discussion and Analysis and the AIF, and provided feedback for changes and improvements to the first quarter financial statements.
- Performed a review of existing accounting policies including embedded derivative review of major contracts, lessee and lessor accounting, segmented reporting, borrowing costs, stock options and more.

**Manager, Forecasts and Budgets**

January 2010 – November 2011

**IFRS Project Manager/Sponsor**

February 2007 – December 2010

**Senior Financial Accountant, Financial Reporting**

February 2007 – March 2010

FortisAlberta Inc.

- Prepared/reviewed monthly, quarterly and annual forecasts and all associated financial analysis for the CFO in comparison to actuals.
- Review of regulatory filings and annual regulatory financial statements submitted to the Alberta Utilities Commission.
- Preparation/review of annual Business Plan for approval by Board of Directors.
- Improvement of monthly and daily treasury forecasts and involvement in debt issuances and responses to due diligence requests.
- Management and review of the monthly tax calculation and development of various tax planning strategies from both a regulatory and financial reporting perspective.
- Assisted in the review of all corporate tax processes and calculation of tax provisions, as well as, design of complex tax planning strategies.
- Responsible for the planning and oversight of the conversion to International Financial Reporting Standards including the review of all policy papers, issues lists, system conversion issues etc.
- Responsible for financial reporting, including the preparation and review of financial statements in accordance with Canadian generally accepted accounting principles, the preparation and review of the MD&A, preparation of the monthly management report, and preparation and review of accounting research and policies.

- Involved in the design, implementation and ongoing improvements of various accounting processes and internal controls within financial reporting, accounts payable, capital assets, inventory, general accounting, treasury, taxation and payroll.
- Provided IFRS transition course for all Finance staff at FortisAlberta.
- Demonstrated effective time management, organization, supervisory and problem solving/analytical skills.

**Vice Chair, CEA's Finance and Accounting Subcommittee** May 2011 – December 2011  
**Member** May 2007 – December 2011

Canadian Electrical Association

- Attended all bi-annual meetings as an active participant involved in presentations at the meetings, organized special purpose conference calls, prepared response letters to both the IASB and AcSB on a variety of topics, and assisted in the special subcommittee on Rate Regulated Accounting.
- Assisted the Chair in the preparation of meeting content, arranging speakers and guest attendees, and other duties as requested.

**IFRS Classroom Facilitator** June 2009 – November 2011

IASeminars

- Classroom facilitator for IASeminars focusing on IFRS accounting within the Utilities and Energy industries.

**Experienced Module Facilitator** January 2006 – September 2009

CA School of Business

- Facilitated Modules 1 to 5 multiple times with class sizes between 8 and 20 students.

**Senior Auditor** September 2003 – February 2007

Deloitte and Touche LLP

- Performed review, audit, SOX 404 and CSOX work for a variety of large multi-national clients including Petro Canada, Potash Corporation, and Superior Propane, as well as review and audit work for smaller to mid-sized for profit and not-for-profit organizations.
- Completed personal tax returns and assisted in the audit of corporate tax provisions.
- Provided audit and oil and gas accounting training to new and existing staff at Deloitte.

## EDUCATION

### **Certified Rate of Return Analyst**

Society of Utility and Regulatory Financial Analysts

### **Certified Depreciation Professional**

Society of Depreciation Professionals

Serving as Vice President beginning January 1, 2025

### **Certified Public Accountant**

Illinois Board of Accountancy

### **Chartered Professional Accountant**

Chartered Professional Accountants of Alberta

**Chartered Accountant**

Institute of Chartered Accountants of Alberta

**Bachelor of Commerce, Major in Accounting, with Great Distinction**

University of Saskatchewan

**LIST OF MAJOR REGULATORY PROCEEDINGS BY REGULATOR**

**((Includes proceedings where testimony was filed, material submissions were prepared, or where testimony is expected to be filed))**

1. New York State Public Service Commission
  - a. New York State Electric & Gas Corporation – Electric rate application – 25-E-0375 – Revenue requirement, infrastructure, cost-of-capital, depreciation, and financial matters.
  - b. New York State Electric & Gas Corporation – Gas rate application – 25-G-0378 – Revenue requirement, infrastructure, cost-of-capital, depreciation, and financial matters.
  - c. Rochester Gas and Electric Corporation – Electric rate application – 25-E-0379 – Revenue requirement, infrastructure, cost-of-capital, depreciation, and financial matters.
  - d. Rochester Gas and Electric Corporation – Gas rate application – 25-G-0380 – Revenue requirement, infrastructure, cost-of-capital, depreciation, and financial matters.
  - e. Consolidated Edison Company of New York, Inc. – Electric rate application – 25-E-0072 – Cost of service, revenue requirement, and financial matters.
  - f. Consolidated Edison Company of New York, Inc. – Gas rate application – 25-G-0073 – Cost of service, revenue requirement, and financial matters.
  - g. Central Hudson Gas & Electric Corporation – Electric rate application – 24-E-0461 – Cost of services, revenue requirement, and other matters.
  - h. Central Hudson Gas & Electric Corporation – Gas rate application – 24-G-0462 – Cost of services, revenue requirement, and other matters.
  - i. Niagara Mohawk Power Corporation d/b/a National Grid – Electric rate cases – 24-E-0322 – Revenue requirement and cost of capital matters.
  - j. Niagara Mohawk Power Corporation d/b/a National Grid – Gas rate cases – 24-G-0323 – Revenue requirement and cost of capital matters.
2. Mississippi Public Service Commission
  - a. Atmos Energy Corporation – Application to change rates to support system integrity plan and continued modernization of infrastructure – 2025-UN-59 – Cost-of-service, revenue allocation, and rate design matters.
  - b. Mississippi Power Company – 2025 Cost of Service Study – 2025-UN-41 – Cost-of-service matters.
  - c. Entergy Mississippi, LLC – December 31, 2022 Unit Cost of Service Study – 2023-UN-142 – Cost-of-service, revenue allocation, and rate design matters.
  - d. Mississippi Power Company – 2024 Cost of Service Study – 2024-UN-21 – Cost-of-service matters.
3. North Carolina Utilities Commission
  - a. Duke Energy Carolinas, LLC and Duke Energy Progress, LLC – Joint Application to Engage in a Business Combination, Address Regulatory Conditions and Code of Conduct, and Request Accounting Order – Docket No. E-7, Sub 1332 and 1383 – Assessment of merger benefits and costs.

4. Public Service Commission of South Carolina
  - a. Dominion Energy South Carolina, Inc. – Application for Authority to Adjust and Increase Its Retail Electric Rates and Charges – Docket No. 2025-325-E – Cost of service, revenue allocation, and rate design.
  - b. Kiawah Island Utility Company – Application for Authority to Adjust and Increase Its Retail Electric Rate Schedules, Tariffs, and Terms and Conditions – Docket No. 2025-343-WS – Cost of service, revenue allocation, rate design, and shared services.
5. Public Utilities Commission of Ohio
  - a. AES Ohio – Application to increase distribution rates for the multi-year period – 25-958-EL-AIR, 25-959-EL-AAM, 25-960-EL-ATA, 25-961-EL-RDR – Revenue requirements, rate base, operating income, cost-of-service, revenue allocation, and rate design matters.
  - b. Aqua Ohio Wastewater, Inc. and Aqua Ohio, Inc. (“Aqua” or “Utility”) – Application for Approval of Distribution Water and Wastewater rates - 25-0593-ST-AIR and 25-0594-WW-AIR – Revenue requirements, rate base, operating income, cost-of-service, revenue allocation, and rate design matters.
  - c. Ohio Power Company – Distribution Rate and Alternative Regulation Cases – 25-392-EL-AIR, 25-393-EL-ATA, and 25-394-EL-AAM – Cost-of-service, revenue allocation, and rate design matters.
  - d. First Energy Ohio – 2025 Request for Increase in rate – 24-0468-EL-AIR – Revenue requirement matters.
  - e. Dominion Energy Ohio – 2024 Alternative Rate Plan – 23-894-GA-AIR – Revenue requirement matters.
6. Arizona Corporation Commission
  - a. Tucson Electric Power Company – Application for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of Tucson Electric Power Company devoted to its operations throughout the State of Arizona and for related approvals – E-01933A-25-0103 – Formula-based rates issues.
  - b. Epcor Water Arizona Inc. –Application of Epcor Water Arizona Inc., San Tan Water and Wastewater Districts, for a Determination of its Water and Wastewater Utility Plant and Property, for Increases in its Rates and Charges for Water and Wastewater Utility Service and for Related Approvals – WS-01303A-24-0130 – Formula-based rates issues.
  - c. Arizona Public Service Company – Application for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Develop Such Return – E-01345A-25-0105 – Formula-based rates issues.
  - d. UNS Gas, Inc. – Application for Establishment of Just and Reasonable Rates and Charges for Utility Service Designed to Realize a Reasonable Rate of Return on the Fair Value of its Property and for Certain Related Approvals – G-04204A-24-0237 – Formula-based rates issues.

- e. Global Water - Santa Cruz Water Company, Inc. – Application for Establishment of Just and Reasonable Rates and Charges for Utility Service Designed to Realize a Reasonable Rate of Return on the Fair Value of its Property and for Certain Related Approvals – W-20446A-25-0022 – Formula-based rates.
  - f. Global Water-Palo Verde Utilities Company, Inc. – Application for Establishment of Just and Reasonable Rates and Charges for Utility Service Designed to Realize a Reasonable Rate of Return on the Fair Value of its Property and for Certain Related Approvals – SW-20445A-25-0023 – Formula-based rates.
  - g. Sulphur Springs Valley Electric Cooperative – Rate Case Application – E-01575A-24-0246 – Cost-of-service and rate design matters.
  - h. Trico Electric Cooperative rate cases – E-01461A-24-0244 – Cost-of-service and rate design matters.
7. Nova Scotia Energy Board
- a. Nova Scotia Power – 2026 General Rate Application – Depreciation and revenue requirement matters.
8. Maryland Public Service Commission
- a. Potomac Electric Power Company – 2025 Rate Case – Docket No. 9820 – Revenue requirement, operating expenses, and infrastructure matters.
9. New Brunswick Energy and Utilities Board
- a. New Brunswick Power – 2026/27 General Rate Application – Matter EL-003-2025 – Revenue requirement, cost-of-capital, depreciation matters, deferral account, information technology, and rate design matters.
  - b. New Brunswick Power - Potential Application pursuant to s. 107 of the *Electricity Act* in Relation to the Renewables Integration and Grid Security (“RIGS”) Project – Board Matter EL-02-2025 – Accounting matters
  - c. Liberty Utilities LP – Gas Cost Review and Review of Unaccounted for Gas – Matter 572/588 – Cost allocation and unaccounted for gas matters.
  - d. Liberty Utilities LP – 2024 General Rate Application – Matter 551 – Revenue requirement matters.
  - e. New Brunswick Power – 2023-2024 Class Cost Allocation Study – Matter 554 – Cost-of-service matters.
  - f. New Brunswick Power – 2024/25 and 2025/26 General Rate Application – Matter 552 – Revenue requirement, cost-of-capital, depreciation matters, deferral account, and information technology matters.
  - g. New Brunswick Power – 2023/24 General Rate Application – Matter 541 – Revenue requirement, depreciation matters, and deferral account matters.
  - h. New Brunswick Power – 2020/21 General Rate Application – Matter 458 – Revenue requirement, cost-of-capital, depreciation matters, and deferral account matters.
10. Ontario Energy Board
- a. TC Energy - TC Energy / TransCanada Mainline tariff settlement negotiations – Cost classification and depreciation matters.

- b. Enbridge Inc. – 2024 Rebasing Application Phase Three – EB-2025-0064 – Cost-of-service and rate design matters.
  - c. Enbridge Inc. – 2024 Rebasing Application Phase Two – EB-2024-0111 – Depreciation matters.
  - d. Enbridge Inc. – 2024 Rebasing Application – EB-2022-0200 – Depreciation matters.
11. Regie De L'Energie
- a. Énergir - Énergir – Application for approval of Gas Supply Plan and amendments to Énergir’s Conditions of Service and Tariff effective October 1, 2025 – Phase 3 – Depreciation and cost capitalization.
12. Manitoba Public Utilities Board
- a. Manitoba Hydro – 2023-2025 General Rate Application – Revenue requirement, depreciation, information technology, and cost-of-service matters.
13. Northwest Territories Public Utilities Board
- a. Naka Power (NWT) Ltd. – 2025 General Rate Application – Revenue requirement, cost-of-capital, depreciation, and cost-of-service.
  - b. Northwest Territories Power Corporation – 2024-26 General Rate Application – Revenue requirement, depreciation, rate of return, and cost-of-service matters.
  - c. Northwest Territories Power Corporation – 2024-25 Interim Rate Application – Revenue requirement and cost sharing matters.
  - d. Northland Utilities (NWT) Ltd. – 2023 General Rate Application – Revenue requirement, cost-of-capital, and cost-of-service.
  - e. Northland Utilities (NWT) Ltd. – Sale of Hay River Assets – Business valuation and cost-of-service.
  - f. Northwest Territories Power Corporation – 2022-23 General Rate Application – Revenue requirement, cost-of-capital, depreciation matters, and deferral account matters.
14. Alberta Utilities Commission
- a. FortisAlberta Inc. – Depreciation Study Application – Proceeding 30504 – Depreciation and net salvage matters.
  - b. ATCO Electric Ltd. – 2026-2027 General Tariff Application – Proceeding 30323 – Revenue requirement, depreciation, income tax, and related matters.
  - c. ATCO Electric and ATCO Gas – Review and Variance Application of Decision 29064-D01-2025 – Proceeding 30141 – Alternative rate plans, reopener mechanisms, cost sharing, and prudence assessments.
  - d. AltaLink Management Ltd. – 2026-2027 General Tariff Application – Proceeding 29879 – Revenue requirement, depreciation, income tax, and related matters.
  - e. Reconsideration of DFO payments under the ISO tariff customer contribution policy – Proceeding 29006 – Investment and cost recovery issues.
  - f. FortisAlberta 2025 Annual Rates Application – Proceeding 29297 – Replacement cost new less depreciation and valuation methodologies.
  - g. PBR3 Reopener Proceedings Stages 1 and 2 – Proceeding 28300 – Alternative rate plans, reopener mechanisms, cost sharing, and prudence assessments.

- h. Generic proceeding – Parameters of Third Generation Performance Based Regulation Plans – Proceeding 27388 – Alternative rate plans, capital-incentive mechanisms, Totex, and sharing mechanisms.
- i. Generic proceeding – 2023 Generic Cost of Capital – Proceeding 27084 – Cost-of-capital.
- j. Generic proceeding – Examination of distribution facility owner payments under the Independent System Operator tariff customer contribution policy – Proceeding 26061 – Cost-of-service.
- k. Generic proceeding – 2018 Generic Cost of Capital and Generic Tax Proceeding – Proceeding 22570 – Cost-of-capital and income taxes.
- l. Generic proceeding – Distributed Generation Review – Proceeding 22534 – Cost-of-service.
- m. Independent System Operator – Bulk and Regional Rate Design and Modernized DOS Rate Design Application – Proceeding 26911 – Revenue requirement and cost-of-service.
- n. Independent System Operator – 2018 ISO Tariff Application – Proceeding 22942 – Revenue requirement and cost-of-service.
- o. ATCO Electric Transmission – 2023-2025 General Tariff Application – Proceeding 27062 – Revenue requirement, deferral accounts, capital expenditures, information technology, and income taxes.
- p. ATCO Electric Transmission – 2020-2022 General Tariff Application – Proceeding 24964 – Revenue requirement, deferral accounts, capital expenditures, information technology, and income taxes.
- q. ATCO Electric Transmission – 2018-2019 General Tariff Application – Proceeding 22742 – Revenue requirement, deferral accounts, capital expenditures, information technology, and income taxes.
- r. ATCO Electric Transmission – 2015-2017 General Tariff Application – Proceeding 20272 – Revenue requirement, deferral accounts, capital expenditures, information technology, and income taxes.
- s. ATCO Electric Transmission – Disposal of 2015-2017 Transmission Deferral Accounts – Proceeding 24375 – Deferral accounts, prudence assessment, and cost and performance audits.
- t. ATCO Electric Transmission – Hanna Project Audit and Deferral Account Application – Proceeding 22393 – Deferral accounts, prudence assessment, and cost and performance audits.
- u. ATCO Electric Transmission – 2013 and 2014 Transmission Deferral Account Application – Proceeding 21206 – Deferral accounts and prudence assessment.
- v. ATCO Electric Distribution and FortisAlberta Inc. – 2023 Cost-of-Service Review – Proceeding 26615 – Revenue requirement and alternative rate plans.
- w. AltaLink – 2024-2025 General Tariff Application – Proceeding 28174 – Revenue requirement, deferral accounts, capital expenditures, information technology, and income taxes.

- x. AltaLink – 2022-2023 General Tariff Application – Proceeding 26509 – Revenue requirement, deferral accounts, depreciation, capital expenditures, information technology, and income taxes.
- y. AltaLink – 2019-2021 General Tariff Application – Proceeding 23848 – Revenue requirement, deferral accounts, depreciation, capital expenditures, information technology, and income taxes.
- z. AltaLink – 2017-2018 General Tariff Application – Proceeding 21341 – Revenue requirement, deferral accounts, capital expenditures, information technology, and income taxes.
- aa. ENMAX – 2014-2015 Transmission Deferral Account and 2015 Distribution Deferral Account – Proceeding 22089 – Deferral accounts and revenue requirement.
- bb. Epcor Distribution and Transmission Inc. - Application to Fix Purchase Price BR REA Annexation – Proceeding 26318 – Business valuation.
- cc. FortisAlberta Inc. – Town of Fort Macleod RCN-D Valuation Application – Proceeding 23972 – Business valuation.

**Potomac Electric Power Company**  
Maryland  
Ratemaking Results - Distribution Only  
Traditional Test Year Compliance Filing (12+0)

(Thousands of Dollars)

**12 Months Ended September 30, 2025**

Line No.	Average Unadjusted (1)	Ratemaking Adjustments (2)	MD Adjusted (3)
<b>RATE BASE</b>			
1	\$ 5,155,529	\$ 109,898	\$ 5,265,427
2	241,325	(62,314)	179,011
3	2,073	-	2,073
4	(1,844,310)	(41,793)	(1,886,103)
5	<u>3,554,616</u>	<u>5,791</u>	<u>3,560,407</u>
6	71,920	-	71,920
7	11,025	(9,714)	1,311
8	(690,402)	(3,840)	(694,242)
9	92,622	-	92,622
10	(39,493)	-	(39,493)
11	17,539	-	17,539
12	20,101	18,047	38,148
13	347	-	347
14			
15	<u><b>\$ 3,038,275</b></u>	<u><b>\$ 10,283</b></u>	<u><b>\$ 3,048,559</b></u>
<b>OPERATING REVENUE</b>			
16			
17	\$ 818,370	\$ 16,187	\$ 834,556
18	8,556	-	8,556
19	<u>\$ 826,926</u>	<u>\$ 16,187</u>	<u>\$ 843,113</u>
<b>OPERATING EXPENSES</b>			
20			
21	\$ 232,686	\$ 580	\$ 233,266
22	153,759	5,730	159,489
23	227,492	6,429	233,921
24	11,009	260	11,269
25	16,602	608	17,210
26	<u>\$ 641,548</u>	<u>\$ 13,607</u>	<u>\$ 655,154</u>
27	\$ 185,378	\$ 2,580	\$ 187,958
<b>ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION</b>			
28	\$ 7,886	\$ (2,743)	5,143
<b>OPERATING INCOME FOR RATE OF RETURN CALCULATION</b>			
29	<u><b>\$ 193,264</b></u>	<u><b>\$ (163)</b></u>	<u><b>\$ 193,101</b></u>
30	<u><b>6.36%</b></u>		<u><b>6.33%</b></u>
31	2.85%		2.85%
32	3.51%		3.49%
33	43.00%		43.00%
<b>For Informational Purposes Only</b>			
34	<u><b>8.17%</b></u>		<u><b>8.11%</b></u>
35			6.16%
36	\$ (8,642)	\$ 1,112	\$ (7,530)
37			<b>7.70%</b>
38			<u><b>\$ 835,582</b></u>

Potomac Electric Power Company

Maryland  
Analysis of Revenue Requirement -- Distribution Only  
Traditional Test Year Compliance Filing (12+0)

(Thousands of Dollars)

		<b>12 Months Ended September 30, 2025</b>			
		<b>Rate Base</b>	<b>Operating Income</b>	<b>AFUDC</b>	<b>Revenue Requirement</b>
Unadjusted amounts		\$ 3,038,275	185,378	\$ 7,886	\$ (8,642)
Adjustments					
1	Annualization of Test Year Reliability Plant Closings	4,823	(470)	(743)	2,109
2	Inclusion of Post Test Year Reliability Closings (Oct-25 - Mar-26)	51,454	(1,406)	(779)	7,478
3	Inclusion of Post Test Year Reliability Closings (Apr-26 - Jul-26)	6,422	(169)	(24)	821
4	Inclusion of Post Test Year Reliability Closings (Aug-26 - Jul-27)	-	-	-	-
5	Reflection of FERC 898 Software Functionalization	1,056	(99)	-	229
6	Annualization of MD Case No. 9702 Revenue	-	11,695	-	(16,340)
7	Annualization of Regulatory Asset Amortization	-	(34)	-	47
8	Removal of Expiring Regulatory Assets	191	(711)	-	1,010
9	July 2023 Major Storm Costs	5,371	(1,194)	-	2,130
10	Reflection of Current Case Costs	-	-	-	-
11	Reflection of Battery Energy Storage Pilot	52	(12)	-	21
12	Reflection of EV Phase I Pilot Costs	296	(66)	-	117
13	Reflection of Supplier Consolidated Billing Costs	(443)	(886)	(152)	1,412
14	Removal of Environmental Activity	-	(5,666)	-	7,916
15	Reflection of Benning Regulatory Asset - Actual Costs	89	(9)	-	21
16	Reflection of Benning Regulatory Asset - Insurance Proceeds	(571)	1,141	-	(1,644)
17	Reflection of Anacostia Regulatory Asset	3,663	(386)	-	854
18	Annualization of Pension Expense	-	(271)	-	378
19	Annualization of Other Post Employment Benefits (OPEB) Expense	-	(9)	-	13
20	Annualization of Wage Increases	-	(2,067)	-	2,889
21	Reflection of 3-Year Average Overtime Expenses	-	63	-	(88)
22	Reflection of 3-Year Average Annual Incentive Plan (AIP) Costs	-	623	-	(871)
23	Reflection of Employee Health & Welfare Cost Increases	-	57	-	(80)
24	Reflection of 3-Year Avg Auto & General Claim Payments	-	(319)	-	446
25	Reflection of 5-year Average Inflation on Non-Labor O&M Expense	-	1,891	-	(2,643)
26	Annualization of Test Period Property Tax Increase	-	(2,830)	-	3,954
27	Reflection of Rate Effective Period Property Tax Increase	-	(1,627)	-	2,273
28	Removal of SERP Expense	-	512	-	(715)
29	Removal of Industry Contributions and Jet Costs	-	763	-	(1,065)
30	Exclusion of Executive Incentive Costs	-	1,669	-	(2,331)
31	Exclusion of 50% Employee Activity Costs	-	254	-	(355)
32	Exclusion of Institutional & Promotional Advertising Expense	-	972	-	(1,358)
33	Inclusion of Commission Authorized Interest Expense	-	(1,173)	-	1,639
34	Reflection of Uncollectible Write-Offs	-	1,042	-	(1,456)
35	Allowance for Funds Used During Construction (AFUDC) Synchronization	-	-	(1,045)	1,461
36	Adjustments to Cash Working Capital Allowance	(9,714)	-	-	(836)
37	Tax Effect of Proforma Interest Expense	-	81	-	(113)
38	Removal of Pepco DC Projects	(897)	180	-	(329)
39	Removal of NOLC	(51,509)	1,039	-	(5,883)
<b>Total adjustments</b>		<b>\$ 10,283</b>	<b>\$ 2,580</b>	<b>\$ (2,743)</b>	<b>\$ 1,112</b>
<b>Total revenue requirement at requested ROR based on adjusted results</b>		<b>\$ 3,048,559</b>	<b>\$ 187,958</b>	<b>\$ 5,143</b>	<b>\$ (7,530)</b>

For Informational Purposes Only

Potomac Electric Power Company

Maryland Ratemaking Adjustments -- Distribution Only  
Traditional Test Year Compliance Filing (12+0)  
12 Months Ended September 30, 2025

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation & Amortization (4)	Other Taxes (5)	MDIT (6)	FIT (7)	Operating Income (8)	AFUDC (9)
1	Annualization of Test Year Reliability Plant Closings				\$ 648		\$ (53)	\$ (125)	\$ (470)	(743)
	Electric Plant in Service	\$ 25,309								
	Accumulated Depreciation and Amortization	5,171								
	Construction Work in Progress	(25,404)								
	Accumulated Deferred Income Taxes	(253)								
2	Inclusion of Post Test Year Reliability Closings (Oct-25 - Mar-26)				1,939		(160)	(374)	\$ (1,406)	(779)
	Electric Plant in Service	75,751								
	Accumulated Depreciation and Amortization	3,374								
	Construction Work in Progress	(27,405)								
	Accumulated Deferred Income Taxes	(265)								
3	Inclusion of Post Test Year Reliability Closings (Apr-26 - Jul-26)				232		(19)	(45)	\$ (169)	(24)
	Electric Plant in Service	9,081								
	Accumulated Depreciation and Amortization	859								
	Construction Work in Progress	(3,391)								
	Accumulated Deferred Income Taxes	(127)								
4	Inclusion of Post Test Year Reliability Closings (Aug-26 - Jul-27)				-		-	-	\$ -	-
	Electric Plant in Service	-								
	Accumulated Depreciation and Amortization	-								
	Construction Work in Progress	-								
	Accumulated Deferred Income Taxes	-								
5	Reflection of FERC 898 Software Functionalization				136		(11)	(26)	\$ (99)	
	Electric Plant in Service	947								
	Accumulated Depreciation and Amortization	184								
	Accumulated Deferred Income Taxes	(75)								
6	Annualization of MD Case No. 9702 Revenue		16,187			52	1,331	3,109	\$ 11,695	
7	Annualization of Regulatory Asset Amortization				46		(4)	(9)	\$ (34)	
8	Removal of Expiring Regulatory Assets			981			(81)	(189)	\$ (711)	
	Regulatory Assets	264								
	Accumulated Deferred Income Taxes	(73)								
9	July 2023 Major Storm Costs				1,647		(136)	(317)	\$ (1,194)	
	Regulatory Assets	7,410								
	Accumulated Deferred Income Taxes	(2,039)								
10	Reflection of Current Case Costs				-		-	-	\$ -	
	Regulatory Assets	-								
	Accumulated Deferred Income Taxes	-								
11	Reflection of Battery Energy Storage Pilot				16		(1)	(3)	\$ (12)	
	Regulatory Assets	72								
	Accumulated Deferred Income Taxes	(20)								
12	Reflection of EV Phase I Pilot Costs				91		(7)	(17)	\$ (66)	
	Regulatory Assets	408								
	Accumulated Deferred Income Taxes	(112)								
13	Reflection of Supplier Consolidated Billing Costs				1,223		(101)	(236)	\$ (886)	(152)



Potomac Electric Power Company

Maryland Ratemaking Adjustments -- Distribution Only  
Traditional Test Year Compliance Filing (12+0)  
12 Months Ended September 30, 2025

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation & Amortization (4)	Other Taxes (5)	MDIT (6)	FIT (7)	Operating Income (8)	AFUDC (9)
	Cash Working Capital	(9,714)								
37	Tax Effect of Proforma Interest Expense						(24)	(56)	\$ 81	
38	Removal of Pepco DC Projects				(248)		20	48	\$ 180	
	Electric Plant in Service	(1,189)								
	Accumulated Depreciation and Amortization	128								
	Accumulated Deferred Income Taxes	164								
39	Removal of NOLC	(51,509)		(1,433)			118	276	1,039	
	<b>Total Ratemaking Adjustments</b>	<b>\$ 10,283</b>	<b>\$ 16,187</b>	<b>\$ 580</b>	<b>\$ 5,730</b>	<b>\$ 6,429</b>	<b>\$ 260</b>	<b>\$ 608</b>	<b>\$ 2,580</b>	<b>\$ (2,743)</b>

**Potomac Electric Power Company**  
Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 1 - Annualization of Test Year Reliability Plant Closings	<u>Adjustment</u>
1	<b>Rate Base</b>	
2	<u>Electric Plant In Service</u>	
3	Annualization of reliability plant closings in test period	\$ 77,166
3	Proposed disallowance of costs	\$ (46,039)
4	Retirements in test period	<u>(5,818)</u>
5	Adjustment to Maryland electric plant in service	\$ 25,309
6	<u>Accumulated Depreciation</u>	
7	Retirements in test period	\$ 5,818
8	Provision for depreciation expense on annualized test period closings	<u>(648)</u>
9	Adjustment to Maryland accumulated depreciation	\$ 5,171
10	<u>CWIP</u>	
11	Adjustment to remove reliability closings from average CWIP	\$ (25,404)
12	<u>Accumulated Deferred Income Taxes</u>	
13	Impact on deferred Maryland income tax	\$ (76)
14	Impact on deferred Federal income tax	<u>(177)</u>
15	Total adjustment to accumulated deferred income taxes	\$ (253)
16	<b>Total Rate Base Adjustment</b>	<b><u>\$ 4,823</u></b>
17	<b>Earnings</b>	
18	<u>Depreciation Expense</u>	
19	Adjustment to Maryland depreciation expense @ 2.56% composite rate	\$ 648
20	<u>Income Taxes</u>	
21	Adjustment to Maryland income tax expense	(53)
22	Adjustment to Federal income tax expense	(125)
23	Adjustment to AFUDC offset	(743)
24	<b>Total Earnings Adjustment</b>	<b><u>\$ (1,213)</u></b>

**Potomac Electric Power Company**  
Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 2 - Inclusion of Post Test Year Reliability Closings (Oct-25 - Mar-26)	<u>Adjustment</u>
1	<b>Rate Base</b>	
2	<u>Electric Plant In Service</u>	
3	Annualization of reliability plant closings in test period	\$ 81,064
4	Retirements in test period	(5,314)
5	Adjustment to Maryland electric plant in service	<u>\$ 75,751</u>
6	<u>Accumulated Depreciation</u>	
7	Retirements in test period	\$ 5,314
8	Provision for depreciation expense on annualized test period closings	(1,939)
9	Adjustment to Maryland accumulated depreciation	<u>\$ 3,374</u>
10	<u>CWIP</u>	
11	Adjustment to remove reliability closings from average CWIP	\$ (27,405)
12	<u>Accumulated Deferred Income Taxes</u>	
13	Impact on deferred Maryland income tax	\$ (80)
14	Impact on deferred Federal income tax	(186)
15	Total adjustment to accumulated deferred income taxes	<u>\$ (265)</u>
16	<b>Total Rate Base Adjustment</b>	<u><u>\$ 51,454</u></u>
17	<b>Earnings</b>	
18	<u>Depreciation Expense</u>	
19	Adjustment to Maryland depreciation expense @ 2.56% composite rate	\$ 1,939
20	<u>Income Taxes</u>	
21	Adjustment to Maryland income tax expense	(160)
22	Adjustment to Federal income tax expense	(374)
23	Adjustment to AFUDC offset	(779)
24	<b>Total Earnings Adjustment</b>	<u><u>\$ (2,184)</u></u>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 3 - Inclusion of Post Test Year Reliability Closings (Apr-26 - Jul-26)	<u>Adjustment</u>
1	<b>Rate Base</b>	
2	<u>Electric Plant In Service</u>	
3	Annualization of reliability plant closings in test period	\$ 10,172
4	Retirements in test period	(1,091)
5	Adjustment to Maryland electric plant in service	<u>\$ 9,081</u>
6	<u>Accumulated Depreciation</u>	
7	Retirements in test period	\$ 1,091
8	Provision for depreciation expense on annualized test period closings	(232)
9	Adjustment to Maryland accumulated depreciation	<u>\$ 859</u>
10	<u>CWIP</u>	
11	Adjustment to remove reliability closings from average CWIP	\$ (3,391)
12	<u>Accumulated Deferred Income Taxes</u>	
13	Impact on deferred Maryland income tax	\$ (38)
14	Impact on deferred Federal income tax	(89)
15	Total adjustment to accumulated deferred income taxes	<u>\$ (127)</u>
16	<b>Total Rate Base Adjustment</b>	<u><u>\$ 6,422</u></u>
17	<b>Earnings</b>	
18	<u>Depreciation Expense</u>	
19	Adjustment to Maryland depreciation expense @ 2.56% composite rate	\$ 232
20	<u>Income Taxes</u>	
21	Adjustment to Maryland income tax expense	(19)
22	Adjustment to Federal income tax expense	(45)
23	Adjustment to AFUDC offset	(24)
24	<b>Total Earnings Adjustment</b>	<u><u>\$ (193)</u></u>

**Potomac Electric Power Company**  
  
Maryland Distribution  
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(Thousands of Dollars)

Line No.	Adjustment 4 - Inclusion of Post Test Year Reliability Closings (Aug-26 - Jul-27)	<u>Adjustment</u>
1	<b>Rate Base</b>	
2	<u>Electric Plant In Service</u>	
3	Annualization of reliability plant closings in test period	
4	Retirements in test period	
5	Adjustment to Maryland electric plant in service	\$ -
6	<u>Accumulated Depreciation</u>	
7	Retirements in test period	\$ -
8	Provision for depreciation expense on annualized test period closings	-
9	Adjustment to Maryland accumulated depreciation	\$ -
10	<u>CWIP</u>	
11	Adjustment to remove reliability closings from average CWIP	
12	<u>Accumulated Deferred Income Taxes</u>	
13	Impact on deferred Maryland income tax	
14	Impact on deferred Federal income tax	
15	Total adjustment to accumulated deferred income taxes	\$ -
16	<b>Total Rate Base Adjustment</b>	<u><u>\$ -</u></u>
17	<b>Earnings</b>	
18	<u>Depreciation Expense</u>	
19	Adjustment to Maryland depreciation expense @ 2.56% composite rate	\$ -
20	<u>Income Taxes</u>	
21	Adjustment to Maryland income tax expense	-
22	Adjustment to Federal income tax expense	-
23	Adjustment to AFUDC offset	
24	<b>Total Earnings Adjustment</b>	<u><u>\$ -</u></u>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 5 - Reflection of FERC 898 Software Functionalization</b>	<b>Adjustment</b>
1	<b>Rate Base</b>	
2	Adjustment to Electric Plant in Service	\$ 947
3	Adjustment to Accumulated Depreciation	184
4	Adjustment to Accumulated Deferred Income Taxes	(75)
5	<b>Total Rate Base Adjustment</b>	<b><u>1,056</u></b>
6	<b>Earnings</b>	
7	Adjustment to Depreciation Expense	\$ 136
8	Adjustment to Maryland income tax expense	(11)
9	Adjustment to Federal income tax expense	(26)
10	<b>Total Earnings Adjustment</b>	<b><u>(99)</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
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(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 6 - Annualization of MD Case No. 9702 Revenue</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Test Year Revenues	\$ 818,370
3	Growth in test year revenues for the rate effective period	2.0%
4	Adjustment to annualize growth in revenues	\$ 16,367
5	Adjustment to annualize billed distribution revenues to levels set in Case No. 9702	\$ 16,187
6	Adjustment to Other Taxes (PSC assessment)	52
7	Adjustment to Maryland Income Tax expense	1,331
8	Adjustment to Federal Income Tax expense	3,109
9	<b>Total Earnings Adjustment</b>	<b><u>\$ 11,695</u></b>

**Potomac Electric Power Company**

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Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 7 - Annualization of Regulatory Asset Amortization</b>	<b>Test Period</b>	<b>Annualized</b>	<b>Adjustment</b>
1	<b>Earnings</b>			
2	Amortization Expense			
3	MD EV	\$ 1,073	\$ 1,116	\$ 43
4	Bus Depot BESS	86	89	4
5	Adjustment to Amortization Expense	<u>\$ 1,158</u>	<u>\$ 1,205</u>	<u>\$ 46</u>
6	Adjustment to Maryland Income Tax expense			(4)
7	Adjustment to Federal Income Tax expense			(9)
8	<b>Total Earnings Adjustment</b>			<u><u>\$ (34)</u></u>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 8 - Removal of Expiring Regulatory Assets	<u>Test Period</u>	<u>Adjustment</u>
1	<b>Earnings</b>		
2	<b>Expired During Testing Period Oct 2024 - Sep 2025</b>		
3	MD Benning Insurance		
4	Adjustment to O&M Expense	\$ (981)	\$ 981
5	Adjustment to Maryland Income Tax expense		(81)
6	Adjustment to Federal Income Tax expense		(189)
7	<b>Total Earnings Adjustment</b>		<b><u><u>\$ (711)</u></u></b>
8	<b>Rate Base</b>		
9	MD Benning Insurance		
10	Adjustment to Regulatory Assets	\$ (264)	\$ 264
11	Adjustment to ADIT	73	(73)
12	<b>Total Rate Base Adjustment</b>		<b><u><u>\$ 191</u></u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 9 - July 2023 Major Storm Costs	<u>Adjustment</u>
1	<b>Earnings</b>	
2	July 2023 Storm Deferred Balance	\$ 8,234
3	Adjustment to Amortization expense to amortize major storm costs over 5 years	1,647
4	Adjustment to Maryland Income Tax expense	(136)
5	Adjustment to Federal Income Tax expense	(317)
6	<b>Total Earnings Adjustment</b>	<u><u>\$ (1,194)</u></u>
		<u>Adjustment</u>
7	<b>Rate Base</b>	
8	Beginning MD Regulatory Asset Balance	\$ 8,234
9	Amortization Expense	1,647
10	Ending MD Regulatory Asset Balance	6,587
11	Average Regulatory Asset Balance	7,410
12	Adjustment to accumulated deferred income taxes	(2,039)
13	<b>Total Rate Base Adjustment</b>	<u><u>\$ 5,371</u></u>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 10 - Reflection of Current Case Costs		<u>Adjustment</u>
1	<b>Earnings</b>		
2	Current Rate Case Costs Estimate	\$ -	
3	Adjustment to Amortization Expense (3 Year Amortization Period)		-
4	Adjustment to MD Income Tax expense		-
5	Adjustment to Federal Income Tax expense		-
6	<b>Total Earnings Adjustment</b>		<u><u>\$ -</u></u>
7	<b>Rate Base</b>		
8	Beginning MD regulatory asset balance	\$ -	
9	Decline in average balance After Year 1		-
10	Total average unamortized rate base balance		-
11	Adjustment to accumulated deferred income taxes		-
12	<b>Total Rate Base Adjustment</b>		<u><u>\$ -</u></u>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 11 - Reflection of Battery Energy Storage Pilot</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Battery Energy Storage Costs - MD Distribution	\$ 80
3	Adjustment to Amortization Expense (5 year amortization period)	16
4	Adjustment to MD income tax expense	(1)
5	Adjustment to federal income tax expense	(3)
6	<b>Total Earnings Adjustment</b>	<b><u>\$ (12)</u></b>
7	<b>Rate Base</b>	
8	Beginning Regulatory Asset Balance	\$ 80
9	Change in Average Regulatory Asset Balance	(8)
10	Total average unamortized rate base balances	72
11	Accumulated Deferred Income Tax	(20)
12	<b>Total Rate Base Adjustment</b>	<b><u>\$ 52</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
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(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 12 - Reflection of EV Phase I Pilot Costs</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Incurred Program Costs	\$ 453
3	Adjustment to Amortization Expense	91
4	Adjustment to MD income tax expense	(7)
5	Adjustment to federal income tax expense	(17)
6	<b>Total Earnings Adjustment</b>	<b><u>\$ (66)</u></b>
7	<b>Rate Base</b>	
8	Beginning Regulatory Asset Balance	\$ 453
9	Decline in Average Regulatory Asset Balance	(45)
10	Adjustment to Regulatory Assets	408
11	Accumulated Deferred Income Tax	(112)
12	<b>Total Rate Base Adjustment</b>	<b><u>\$ 296</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 13 - Reflection of Supplier Consolidated Billing Costs</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Supplier Consolidated Billing Costs	\$ 7,189
3	Distribution Allocator	85.0%
4	Supplier Consolidated Billing Costs - Distribution	6,114
5	Adjustment to Amortization Expense (5 Year Amortization Period)	1,223
6	Adjustment to MD income tax expense	(101)
7	Adjustment to federal income tax expense	(236)
8	Adjustment to AFUDC Offset	(152)
9	<b>Total Earnings Adjustment</b>	<b><u>\$ (1,038)</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 14 - Removal of Environmental Activity</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Total distribution-related charge for Benning environmental accrual and liability included in Distribution O&M	\$ (4,007)
3	Allocation to MD - Benning Allocation	42.3%
4	Total distribution-related charge for Anacostia environmental liability true-up included in Distribution O&M	(12,573)
5	Allocation to MD - STDPLT Allocation	48.7%
6	Adjustment to MD O&M Expense	7,817
7	Adjustment to state income tax expense	(645)
8	Adjustment to federal income tax expense	(1,506)
9	<b>Total Earnings Adjustment</b>	<b><u>\$ (5,666)</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 15 - Reflection of Benning Regulatory Asset - Actual Costs</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Deferred Benning Costs - April 2025 - September 2025	\$ 305
3	Allocation factor - Maryland (Benning Allocator)	42.3%
4	Pepco MD Allocated Deferred Costs	129
5	Adjustment to O&M for Amortization Expense (10 year amortization period)	13
6	Adjustment to MD income tax expense	(1)
7	Adjustment to Federal income tax expense	(2)
8	<b>Total Earnings Adjustment</b>	<b><u>\$ (9)</u></b>
9	<b>Rate Base</b>	
10	Beginning Regulatory Asset Balance	\$ 129
11	Decline in Average Regulatory Asset Balance	(6)
12	Total average unamortized rate base balance	122
13	Adjustment to accumulated deferred income taxes	(34)
14	<b>Total Rate Base Adjustment</b>	<b><u>\$ 89</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 16 - Reflection of Benning Regulatory Asset - Insurance Proceeds</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Benning Insurance Proceeds	\$ (3,722)
3	Allocation to MD	42.3%
4	Benning Insurance Proceeds - Distribution MD	(1,575)
5	Adjustment to Amortization Expense (1 year amortization period)	(1,575)
6	Adjustment to Maryland Income Tax expense	130
7	Adjustment to Federal Income Tax expense	303
8	<b>Total Earnings Adjustment</b>	<b><u>\$ 1,141</u></b>
9	<b>Rate Base</b>	
10	Average MD regulatory asset balance	\$ (1,575)
11	Decline in balance After Year 1	787
12	Total average unamortized rate base balances	(787)
13	Average unamortized regulatory liability balance	(787)
14	Adjustment to accumulated deferred income taxes	217
15	<b>Total Rate Base Adjustment</b>	<b><u>\$ (571)</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 17 - Reflection of Anacostia Regulatory Asset	<u>Adjustment</u>
1	<b>Anacostia Insurance Proceeds</b>	
2	Available Anacostia insurance proceeds	\$ 12,573
3	Allocation to MD - STDPLT	48.7%
4	MD allocated Anacostia insurance proceeds	6,122
5	<b>ARSP Costs</b>	
6	Test Year ARSP Costs - DOEE Payment for Clean Land Fund - April 2025	\$ 11,750
7	Post Test Year ARSP Costs - DOEE Payment for Clean Land Fund - April 2026	11,750
8	Allocation to MD - STDPLT	48.7%
9	Incremental Pepco MD Allocated Cost	11,442
10	Pepco MD Allocated Cost Net of Available Insurance Proceeds	5,320
11	<b>Earnings</b>	
12	Adjustment to Amortization Expense (10 year amortization period)	\$ 532
13	Adjustment to state income tax expense	(44)
14	Adjustment to federal income tax expense	(103)
15	<b>Total Earnings Adjustment</b>	<u>\$ (386)</u>
16	<b>Rate Base</b>	
17	Beginning Regulatory Asset Balance	\$ 5,320
18	Decline in Average Regulatory Asset Balance	(266)
19	Adjustment to Regulatory Assets	5,054
20	Adjustment to accumulated deferred income taxes	(1,391)
21	<b>Total Rate Base Adjustment</b>	<u>\$ 3,663</u>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 18 - Annualization of Pension Expense</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Distribution-related Pension expense in 2025	\$ 17,217
3	Distribution-related Pension expense reflected in test period	16,562
4	Change in Pepco Distribution-related O&M Pension/OPEB expense	655
5	Allocation factor - Maryland (O&M less A&G and Storm Costs)	57.0%
6	Adjustment to Maryland Distribution O&M expense	373
7	Adjustment to Maryland Income Tax expense	(31)
8	Adjustment to Federal Income Tax expense	(72)
9	<b>Total Earnings Adjustment</b>	<b><u>\$ (271)</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
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(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 19 - Annualization of Other Post Employment Benefits (OPEB) Expense</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Distribution-related OPEB expense in 2025	\$ 2,240
3	Distribution-related OPEB expense reflected in test period	2,218
4	Change in Pepco Distribution-related O&M OPEB expense	23
5	Allocation factor - Maryland (O&M less A&G and Storm Costs)	57.0%
6	Adjustment to Maryland Distribution O&M expense	13
7	Adjustment to Maryland Income Tax expense	(1)
8	Adjustment to Federal Income Tax expense	(2)
9	<b>Total Earnings Adjustment</b>	<b>\$ (9)</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line

**No. Adjustment 20 - Annualization of Wage Increases**

	<u>Mgmt</u>	<u>Union</u>	<u>Adjustment</u>
1	<b>Earnings</b>		
2	<b><u>ANNUALIZATION OF TEST YEAR INCREASES (3/1/2025 MGMT, 6/1/2025 UNION)</u></b>		
3	Distr-related O&M wages/overtime, excl one-time payments, before increases		
4	<b>Pepco</b>		
5	\$ 7,857	\$ 18,411	
6	247	3,580	
7	<u>\$ 8,104</u>	<u>\$ 21,991</u>	
8	<b>Charged to Pepco from Service Company</b>		
9	\$ 11,389	\$ 2,244	
10	17	100	
11	<u>\$ 11,405</u>	<u>\$ 2,344</u>	
12	<b>Charged to Pepco from EBSC</b>		
13	\$ 10,315	\$ -	
14	178	-	
15	<u>\$ 10,493</u>	<u>\$ -</u>	
16	3.00%	4.00%	
17	Adjustment to annualize wage increases occurring in test year:		
18	\$ 243	\$ 880	
19	342	94	
20	315	-	
21	<u><u>\$ 900</u></u>	<u><u>\$ 973</u></u>	<u><u>\$ 1,873</u></u>
22	<b><u>ADJUSTMENT TO REFLECT INCREASES WITHIN 12 MOS. OF TEST YEAR</u></b>		
23	\$ 20,989	\$ 29,461	
24	700	5,979	
25	243	880	
26	<u>\$ 21,932</u>	<u>\$ 36,320</u>	
27	\$ 31,130	\$ 3,479	
28	103	175	
29	342	94	
30	<u>\$ 31,574</u>	<u>\$ 3,748</u>	
31	\$ 26,289	\$ -	
32	408	-	
33	315	-	
34	<u>\$ 27,012</u>	<u>\$ -</u>	
35	3.00%	3.00%	
36	Adjustment to annualize known increases in rate effective period:		
37	\$ 658	\$ 1,090	
38	947	112	
39	810	-	
40	<u><u>\$ 2,416</u></u>	<u><u>\$ 1,202</u></u>	<u><u>\$ 3,618</u></u>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line

No. Adjustment 20 - Annualization of Wage Increases

	<u>Mgmt</u>	<u>Union</u>	<u>Adjustment</u>
41	<b><u>ADJUSTMENT TO REFLECT INCREASES IN RATE EFFECTIVE PERIOD</u></b>		
42	Pre-Rate Eff Annualization Adjustment		
43	\$ 658	\$ 1,090	
44	947	112	
45	810	-	
46	<b>Total adjustment</b>	<b>2,416</b>	<b>1,202</b>
47	3.00%	3.00%	
48	58.33%	83.33%	
49	Rate Eff Annualization Adjustment		
50	\$ 384	\$ 908	
51	553	94	
52	473	-	
53	<b>Total adjustment</b>	<b>\$ 1,002</b>	<b>\$ 2,411</b>
54	<b><u>ADJUSTMENT TO REFLECT END OF PERIOD HEADCOUNT</u></b>		
55	\$ 1,285	\$ 2,877	
56	Full Time Employee Count-Pepco		
57	496	791	
58	513	803	
59	103.43%	101.52%	
60	<b>Pepco Headcount Adjustment ((line 55 x line 59) - line 55)</b>	<b>44</b>	<b>44</b>
61	\$ 1,842	\$ 300	
62	Full Time Employee Count-Servco		
63	1,062	194	
64	1,094	188	
65	103.01%	96.91%	
66	<b>Servco Headcount Adjustment ((line 61 * line 65) - line 61)</b>	<b>55</b>	<b>(9)</b>
67	\$ 1,598	\$ -	
68	Employee Count-EBSC		
69	2,768	-	
70	2,843	-	
71	102.71%	-	
72	<b>EBSC Headcount Adjustment ((line 67 x line 71) - line 67)</b>	<b>43</b>	<b>-</b>

Potomac Electric Power Company

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(Thousands of Dollars)

Line

No. Adjustment 20 - Annualization of Wage Increases

	<u>Mgmt</u>	<u>Union</u>	<u>Adjustment</u>
73	<b>TOTAL ADJUSTMENT TO WAGES</b>		
74	\$ 1,329	\$ 2,921	
75	1,897	291	
76	1,641	-	
77	<b>\$ 4,867</b>	<b>\$ 3,212</b>	<b>\$ 8,079</b>
78	57.0%	57.0%	57.0%
79	\$ 1,576	\$ 1,042	\$ 2,618
80	141	93	234
81			(235)
82			\$ (550)
83	<b>Total Earnings Adjustment</b>		<b>\$ (2,067)</b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 21 - Reflection of 3-Year Average Overtime Expenses	Total	Incremental Major Storm Cost	Overtime Excl. Storm Costs
1	<b>Earnings</b>			
2	12 mos. ended September 2023 overtime, net of storm costs	\$ 8,707	\$ (645)	\$ 8,062
3	12 mos. ended September 2024 overtime, net of storm costs	6,249	-	6,249
4	12 mos. ended September 2025 overtime, net of storm costs	7,366	-	7,366
5	3-year total overtime, net of storm costs	22,322	(645)	21,677
6	3-year average overtime, net of storm costs			7,226
7	Overtime included in test year			7,366
8	Net adjustment to overtime			(140)
9	Allocation to MD (O&M less A&G and Storm Costs ratio)			57.0%
10	Adjustment to MD operations and maintenance expense			(80)
11	Adjustment to MD payroll taxes			(7)
12	Adjustment to MD income tax expense			7
13	Adjustment to Federal income tax expense			17
14	<b>Total Earnings Adjustment</b>			<b><u>\$ 63</u></b>

**Potomac Electric Power Company**

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12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 22 - Reflection of 3-Year Average Annual Incentive Plan (AIP) Costs	<u>Adjustment</u>
1	<b>Earnings</b>	
2	Distribution-related AIP costs:	
3	Twelve months ended September 30, 2023	\$ 14,517
4	Twelve months ended September 30, 2024	15,059
5	Twelve months ended September 30, 2025	17,052
6	Total AIP Costs	46,627
7	3-year average AIP costs (Line 6 ÷ 3)	15,542
8	AIP costs reflected in test period	17,052
9	Adjustment to reflect 3-year average AIP costs	(1,509)
10	Maryland O&M less A&G and Storm Costs ratio	57.0%
11	Adjustment to Maryland operating & maintenance expense	(860)
12	Adjustment to Maryland income tax expense	71
13	Adjustment to federal income tax expense	166
14	<b>Total Earnings Adjustment</b>	<b><u>\$ 623</u></b>

Potomac Electric Power Company

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12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 23 - Reflection of Employee Health & Welfare Cost Increases	<u>Test Period</u>	<u>3-Yr Avg Change</u>	<u>Adjustment</u>
1	<b>Earnings</b>			
2	Shared Benefits costs in O&M Expense			
3	Medical	\$ 12,039	-0.9%	\$ (108)
4	Dental	576	-3.9%	(22)
5	Vision	15	-47.4%	(7)
6	Total Shared Benefits	<u>\$ 12,630</u>		<u>\$ (138)</u>
7	Allocation to distribution (labor ratio)			85.0%
8	Adjustment to distribution-related O&M expense			(117)
9	Direct Distribution shared benefits charged to O&M			
10	Medical	\$ 1,738	-0.9%	\$ (16)
11	Dental	86	-3.9%	(3)
12	Vision	4	-47.4%	(2)
13	Total Distribution Direct	<u>\$ 1,828</u>		<u>\$ (21)</u>
14	Total adjustment to distribution			(138)
15	Allocation to MD (O&M less A&G and Storm Costs ratio)			57.0%
16	Adjustment to MD O&M expense			(79)
17	Adjustment to MD income tax expense			6
18	Adjustment to federal income tax expense			15
19	<b>Total Earnings Adjustment</b>			<u><u>\$ 57</u></u>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 24 - Reflection of 3-Year Avg Auto & General Claim Payments	<u>Adjustment</u>
1	<b>Earnings</b>	
2	Auto and general claims liability expense accrued in the test period	\$ 763
3	<u>Claim payments, net of receipts</u>	
4	Twelve months ended September 30, 2023	2,000
5	Twelve months ended September 30, 2024	2,113
6	Twelve months ended September 30, 2025	901
7	3-year average auto and general claims paid	1,671
8	Adjustment to O&M expense to reflect 3-year average claims paid (Line 7 - Line 1)	908
9	Allocation to distribution (labor ratio)	85.0%
10	Adjustment to distribution-related expense	773
11	Allocation to Maryland (O&M less A&G and Storm Costs ratio)	57.0%
12	Adjustment to Maryland allocated O&M expense for auto and general claims	440
13	Adjustment to Maryland income tax expense	(36)
14	Adjustment to federal income tax expense	(85)
15	<b>Total Earnings Adjustment</b>	<b><u>\$ (319)</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 25 - Reflection of 5-year Average Inflation on Non-Labor O&amp;M Expense</b>	<b><u>Adjustment</u></b>
1	<b>Earnings</b>	
2	Unadjusted Maryland Distribution O&M Expense	\$ 232,686
3	LESS:	
4	RMA 18 - Pension	9,439
5	RMA 19 - OPEB	1,264
6	RMA 20 - Base Wages	63,460
7	RMA 21 - Overtime	4,198
8	RMA 22 - AIP	9,718
9	RMA 23 - Benefits	7,164
10	RMA 24 - Claims	370
11	RMA 28 - SERP	706
12	RMA 29 - Contributions and Jet	1,052
13	RMA 30 - Executive Incentive	2,302
14	RMA 31 - Employee Activity	702
15	RMA 32 - Advertising	1,341
16	RMA 34 - Uncollectibles	10,189
17	MD Reg Asset Amortizations in O&M	1,166
18	Total Deductions	<u>\$ 113,070</u>
19	O&M After Deductions for Items above	119,617
20	Inflation Factor (Forecast inflation)	2.50%
21	Reduction for corrective maintenance work deferral	\$ (5,600)
22	Adjustment to O&M Expense	(2,610)
23	Adjustment to MD Income Taxes	215
24	Adjustment to Federal Income Taxes	503
25	<b>Total Earnings Adjustment</b>	<b><u><u>\$ 1,891</u></u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 26 - Annualization of Test Period Property Tax Increase	<u>Adjustment</u>
1	<b>Earnings</b>	
2	<u>Test Period</u>	
3	Total Pepco - Test Period Maryland Property Taxes	\$ 76,670
4	Distribution Allocation Factor	<u>76.1%</u>
5	Total Pepco Distribution - Test Period Maryland Property Taxes	\$ 58,323
6	Maryland Allocation Factor	<u>94.6%</u>
7	Total Pepco Distribution Maryland - Test Period Maryland Property Taxes	\$ 55,186
8	<u>Fiscal Year 2026 (July 1, 2025 - June 30, 2026)</u>	
9	Total PEPCO MD - Fiscal Year Property Tax Assessment	\$ 2,736,753
10	Total PEPCO - Fiscal Year Maryland Property Taxes	82,095
11	Total PEPCO Distribution- Fiscal Year Maryland Property Taxes	62,450
12	Total PEPCO Distribution Maryland - Fiscal Year Maryland Property Taxes	59,091
13	Adjustment to Other Tax Expense (Line 9 - Line 4)	3,905
14	Adjustment to Maryland income tax expense	(322)
15	Adjustment to federal income tax expense	(752)
16	<b>Total Earnings Adjustment</b>	<b><u><u>\$ (2,830)</u></u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 27 - Reflection of Rate Effective Period Property Tax Increase	Adjustment
1	<b>Earnings</b>	
2	<u>Fiscal Year 2026 (July 1, 2025 - June 30, 2026)</u>	
3	FY Property Tax Assessment	\$ 2,736,753
4	Total PEPCO - Fiscal Year Maryland Property Taxes	82,095
5	Distribution Allocation Factor	<u>76.1%</u>
6	Total PEPCO Distribution- Fiscal Year Maryland Property Taxes	62,450
7	Maryland Allocation Factor	<u>94.6%</u>
8	Total PEPCO Distribution Maryland - Fiscal Year Maryland Property Taxes	59,091
9	<u>Fiscal Year 2027 (July 1, 2026 - June 30, 2027)</u>	
10	Prior Fiscal Year Assessments	
11	Fiscal Year 2021 Assessment (2020 Assessment Year)	\$ 2,033,053
12	Fiscal Year 2022 Assessment (2021 Assessment Year)	2,212,627
13	Fiscal Year 2023 Assessment (2022 Assessment Year)	2,390,160
14	Fiscal Year 2024 Assessment (2023 Assessment Year)	2,475,399
15	Fiscal Year 2025 Assessment (2024 Assessment Year)	2,736,753
16	Percent Change in Fiscal Year Assessments	
17	Fiscal Year 2022 vs. Fiscal Year 2021	8.8%
18	Fiscal Year 2023 vs. Fiscal Year 2022	8.0%
19	Fiscal Year 2024 vs. Fiscal Year 2023	3.6%
20	Fiscal Year 2025 vs. Fiscal Year 2024	<u>10.6%</u>
21	Average Change in Fiscal Year Assessment	7.7%
22	Fiscal Year Property Tax Assessment	\$ 2,948,720
23	Total Pepco - Fiscal Year 2025 Maryland Property Taxes	88,453
24	Total Pepco Distribution- Fiscal Year 2025 Maryland Property Taxes	67,287
25	Total Pepco Distribution Maryland - Fiscal Year 2025 Maryland Property Taxes	63,668
26	Ratio of RMA 2 adjustment to Property taxes (Relative to RMA 2, 3, and 4)	49.05%
27	Adjustment to Other Tax Expense (Line 10 - Line 5)	2,245
28	Adjustment to Maryland income tax expense	(185)
29	Adjustment to federal income tax expense	(433)
30	<b>Total Earnings Adjustment</b>	<u><u>\$ (1,627)</u></u>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 28 - Removal of SERP Expense</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Total distribution SERP expense	\$ 1,238
3	Allocation to Maryland (O&M less A&G and Storm Costs ratio)	57.0%
4	Remove Maryland distribution SERP expense	(706)
5	Adjustment to Maryland income tax expense	58
6	Adjustment to federal income tax expense	136
7	<b>Total Earnings Adjustment</b>	<b><u>\$ 512</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 29 - Removal of Industry Contributions and Jet Costs	<u>Adjustment</u>
1	<b>Earnings</b>	
2	Industry Association Dues	\$ 541
3	Industry Corporate Jet Fees	1,569
4	Allocation to Distribution (Labor Ratio)	85.0%
5	Excludable industry contributions & membership fees included in distribution O&M	1,795
6	Allocation to M.D. (O&M less A&G ratio and storms)	57.0%
7	Other amounts not removed	29
8	Adjustment to M.D. operations and maintenance expense	(1,052)
9	Adjustment to M.D. income tax expense	87
10	Adjustment to Federal income tax expense	203
11	<b>Total Earnings Adjustment</b>	<b><u>\$ 763</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	Adjustment 30 - Exclusion of Executive Incentive Costs	<u>Adjustment</u>
1	<b>Earnings</b>	
2	Distribution-related executive incentive costs to remove from O&M expense	\$ 3,637
3	Adjustment to remove Earnings-Related CEO EIP Expense	70
4	Adjustment to remove Earnings-Related Exelon CEO & Direct Report Executives EIP Expense	332
5	Distribution-related incentive costs in Pepco O&M expense	4,039
6	Allocation to Maryland (O&M less A&G and Storm Costs ratio)	57.0%
7	Maryland allocated executive incentive costs	2,302
8	Adjustment to Maryland O&M expense to remove allocated executive incentive costs	(2,302)
9	Adjustment to Maryland income tax expense	190
10	Adjustment to federal income tax expense	444
11	<b>Total Earnings Adjustment</b>	<b><u>\$ 1,669</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 31 - Exclusion of 50% Employee Activity Costs</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Total distribution employee activity costs incurred in test period	1,232
3	Allocation to Maryland (O&M less A&G and Storms ratio)	57.0%
4	Maryland distribution O&M expense	702
5	Remove Maryland distribution O&M expense - employee activity costs	(702)
6	Exclusion of 50% per Order No. 85724	50%
7	Adjustment to Maryland distribution O&M expense	(351)
8	Adjustment to Maryland Income Tax expense	29
9	Adjustment to Federal Income Tax expense	68
10	<b>Total Earnings Adjustment</b>	<b><u>\$ 254</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 32 - Exclusion of Institutional &amp; Promotional Advertising Expense</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Institutional and promotional advertising expenses (Acct 930.1 and Other)	\$ 2,353
3	Allocation to MD (O&M less A&G and Storm Costs ratio)	57.0%
4	Adjustment to MD O&M expense to remove allocated institutional advertising	(1,341)
5	Adjustment to MD income tax expense	111
6	Adjustment to federal income tax expense	258
7	<b>Total Earnings Adjustment</b>	<b><u>\$ 972</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 33 - Inclusion of Commission Authorized Interest Expense</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Interest on customer deposits at 3.64%	\$ 1,413
3	Credit facility costs (quarterly maintenance fee)	424
4	Allocation to Distribution (Labor ratio)	85.0%
5	Distribution-related credit facility costs	360
6	Allocation factor - Maryland (O&M less A&G ratio and storms)	57.0%
7	Maryland allocated credit facility costs	205
8	Adjustment to include Commission-allowed interest charges in distribution O&M expense	1,618
9	Adjustment to Maryland income tax expense	(134)
10	Adjustment to Federal income tax expense	(312)
11	<b>Total Earnings Adjustment</b>	<b><u>\$ (1,173)</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 34 - Reflection of Uncollectible Write-Offs</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Maryland distribution-related uncollectible write-offs, net of recoveries	\$ 8,752
3	Maryland distribution-related uncollectible accrued expense	10,189
4	Adjustment to Maryland distribution O&M expense to reflect net uncollectible write-offs (Line 1 - 2)	(1,437)
5	Adjustment to Maryland income tax expense	119
6	Adjustment to federal income tax expense	277
7	<b>Total Earnings Adjustment</b>	<b><u>\$ 1,042</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 35 - Allowance for Funds Used During Construction (AFUDC) Synchronization</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Average CWIP accruing AFUDC	\$ 111,094
3	Maryland proposed rate of return	6.16%
4	AFUDC distribution income add-back	6,840
5	Distribution related MD AFUDC per book accrual	7,886
6	Adjustment to AFUDC offset	\$ (1,045)
7	<b>Total Earnings Adjustment</b>	<b>\$ (1,045)</b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<u>Line No.</u>	<u>Adjustment 36 - Adjustments to Cash Working Capital Allowance</u>	<u>Adjustment</u>
1	<b>Rate Base</b>	
2	Reflection of lag on interest expense	\$ (9,690)
2	Impact of proforma ratemaking adjustments on cash working capital	(25)
3	<b>Adjustment to cash working capital allowance</b>	<b><u>\$ (9,714)</u></b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

Line No.	RMA No.	Adjustment 36 - Adjustments to Cash Working Capital Allowance	REVENUE	O&M	DEPR/ AMORT	OTHER TAXES	SIT	FIT	TOTAL EXPENSE	AFUDC	EARNINGS	RATE BASE
1		Maryland Unadjusted Results	\$ 826,926	\$ 232,686	\$ 153,759	\$ 227,492	\$ 11,009	\$ 16,602	\$ 641,548	\$ 7,886	\$ 193,264	\$ 3,038,275
2		Ratemaking Adjustments										
3	1	Annualization of Test Year Reliability Plant Closings	-	-	648	-	(53)	(125)	470	(743)	(1,213)	4,823
4	2	Inclusion of Post Test Year Reliability Closings (Oct-25 - Mar-26)	-	-	1,939	-	(160)	(374)	1,406	(779)	(2,184)	51,454
5	3	Inclusion of Post Test Year Reliability Closings (Apr-26 - Jul-26)	-	-	232	-	(19)	(45)	169	(24)	(193)	6,422
6	4	Inclusion of Post Test Year Reliability Closings (Aug-26 - Jul-27)	-	-	-	-	-	-	-	-	-	-
7	5	Reflection of FERC 898 Software Functionalization	-	-	136	-	(11)	(26)	99	-	(99)	1,056
8	6	Annualization of MD Case No. 9702 Revenue	16,187	-	-	52	1,331	3,109	4,492	-	11,695	-
9	7	Annualization of Regulatory Asset Amortization	-	-	46	-	(4)	(9)	34	-	(34)	-
10	8	Removal of Expiring Regulatory Assets	-	981 *	-	-	(81)	(189)	711	-	(711)	191
11	9	July 2023 Major Storm Costs	-	-	1,647	-	(136)	(317)	1,194	-	(1,194)	5,371
12	10	Reflection of Current Case Costs	-	-	-	-	-	-	-	-	-	-
13	11	Reflection of Battery Energy Storage Pilot	-	-	16	-	(1)	(3)	12	-	(12)	52
14	12	Reflection of EV Phase I Pilot Costs	-	-	91	-	(7)	(17)	66	-	(66)	296
15	13	Reflection of Supplier Consolidated Billing Costs	-	-	1,223	-	(101)	(236)	886	(152)	(1,038)	(443)
16	14	Removal of Environmental Activity	-	7,817 *	-	-	(645)	(1,506)	5,666	-	(5,666)	-
17	15	Reflection of Benning Regulatory Asset - Actual Costs	-	13 *	-	-	(1)	(2)	9	-	(9)	89
18	16	Reflection of Benning Regulatory Asset - Insurance Proceeds	-	(1,575) *	-	-	130	303	(1,141)	-	1,141	(571)
19	17	Reflection of Anacostia Regulatory Asset	-	532 *	-	-	(44)	(103)	386	-	(386)	3,663
20	18	Annualization of Pension Expense	-	373 *	-	-	(31)	(72)	271	-	(271)	-
21	19	Annualization of Other Post Employment Benefits (OPEB) Expense	-	13 *	-	-	(1)	(2)	9	-	(9)	-
22	20	Annualization of Wage Increases	-	2,618	-	234	(235)	(550)	2,067	-	(2,067)	-
23	21	Reflection of 3-Year Average Overtime Expenses	-	(80)	-	(7)	7	17	(63)	-	63	-
24	22	Reflection of 3-Year Average Annual Incentive Plan (AIP) Costs	-	(860)	-	-	71	166	(623)	-	623	-
25	23	Reflection of Employee Health & Welfare Cost Increases	-	(79)	-	-	6	15	(57)	-	57	-
26	24	Reflection of 3-Year Avg Auto & General Claim Payments	-	440	-	-	(36)	(85)	319	-	(319)	-
27	25	Reflection of 5-year Average Inflation on Non-Labor O&M Expense	-	(2,610)	-	-	215	503	(1,891)	-	1,891	-
28	26	Annualization of Test Period Property Tax Increase	-	-	-	3,905	(322)	(752)	2,830	-	(2,830)	-
29	27	Reflection of Rate Effective Period Property Tax Increase	-	-	-	2,245	(185)	(433)	1,627	-	(1,627)	-
30	28	Removal of SERP Expense	-	(706)	-	-	58	136	(512)	-	512	-
31	29	Removal of Industry Contributions and Jet Costs	-	(1,052)	-	-	87	203	(763)	-	763	-
32	30	Exclusion of Executive Incentive Costs	-	(2,302)	-	-	190	444	(1,669)	-	1,669	-
33	31	Exclusion of 50% Employee Activity Costs	-	(351)	-	-	29	68	(254)	-	254	-
34	32	Exclusion of Institutional & Promotional Advertising Expense	-	(1,341)	-	-	111	258	(972)	-	972	-
35	33	Inclusion of Commission Authorized Interest Expense	-	1,618	-	-	(134)	(312)	1,173	-	(1,173)	-
36	34	Reflection of Uncollectible Write-Offs	-	(1,437)	-	-	119	277	(1,042)	-	1,042	-
37	35	Allowance for Funds Used During Construction (AFUDC) Synchronization	-	-	-	-	-	-	-	(1,045)	(1,045)	-
38	38	Removal of Pepco DC Projects	-	-	(248)	-	20	48	(180)	-	180	(897)
39		<b>Subtotal Ratemaking Adjustments</b>	<b>\$ 16,187</b>	<b>\$ 2,013</b>	<b>\$ 5,730</b>	<b>\$ 6,429</b>	<b>\$ 166</b>	<b>\$ 388</b>	<b>\$ 14,726</b>	<b>\$ (2,743)</b>	<b>\$ (1,282)</b>	<b>\$ 3,109,782</b>
40		Proforma Interest Expense							\$ 85,355			
41		Cash Working Capital Ratio							-11.35%			
42		<b>Interest Expense Lag</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ (9,690)</b>			
43		Subtotal Ratemaking Adjustments (Line 38)	\$ 16,187	\$ 2,013	\$ 5,730	\$ 6,429	\$ 166	\$ 388				
44		Less: Non-Cash or Expense Not Lagged in CWC *	-	(8,154)	-	-	673	1,571				
45		Subtotal Ratemaking Adjustments with CWC Impact	\$ 16,187	\$ (6,141)	\$ 5,730	\$ 6,429	\$ 839	\$ 1,959				
46		Cash Working Capital Ratio		2.79%	0.00%	2.28%	0.00%	0.00%				
47		<b>Proforma Impact of RMA Nos. 1-35, 38</b>	<b>\$ -</b>	<b>\$ (172)</b>	<b>\$ -</b>	<b>\$ 147</b>	<b>\$ -</b>	<b>\$ -</b>				
48	41	Tax Effect of Proforma Interest Expense					\$ (89)	\$ (208)				
49		Cash Working Capital Ratio					0.00%	0.00%				
50		<b>Proforma Impact of RMA No. 37</b>					<b>\$ -</b>	<b>\$ -</b>				
51		Adjusted rate base before proforma adjustments	\$ 3,109,782	\$ 2,998,688	\$ 2,988,974							
52		Less: Average CWIP Accruing AFUDC	\$ (111,094)									
53		Plus: Impact of Interest Expense Lag		(9,690)	-							
54		Plus: Impact of RMA Nos. 1-15		(25)	-							
55		Plus: Impact Interest Synchronization			-							
56		Average Rate Base for Interest Synchronization	\$ 2,998,688	\$ 2,988,974	\$ 2,988,974							
57		Weighted cost of long term debt	2.85%	2.85%	2.85%							
58		Pro-forma interest	\$ 85,355	\$ 85,078	\$ 85,078							
59		Less: Per book interest expense		(83,999)	(85,078)							
60		Change to interest expense		\$ 1,079	\$ -							
61		Adjustment to Maryland Income Tax		\$ (89)	\$ -							
62		Adjustment to Federal Income Tax		\$ (208)	\$ -							

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line No.</b>	<b>Adjustment 37 - Tax Effect of Proforma Interest Expense</b>	<b>Adjustment</b>
1	<b>Earnings</b>	
2	Ratemaking adjustments to average MD rate base	\$ 10,283
3	Weighted cost of long term debt	2.85%
4	Pro-forma interest	293
5	Adjustment to Maryland income tax for pro-forma interest expense	(24)
6	Adjustment to federal income tax for pro-forma interest expense	(56)
7	<b>Total Earnings Adjustment</b>	<b><u>\$ 81</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<b>Line</b>	<b>Adjustment 38 - Removal of Pepco DC Projects</b>	<b>Adjustment</b>
1	<b>Rate Base</b>	
2	Average Electric Plant in Service	\$ 2,872
3	Allocation Factor - Distribution (S&W)	85.0%
4	Allocation Factor - Maryland (STDPLT)	48.7%
5	Adjustment to MD Allocated Electric Plant in Service	(1,189)
6	Adjustment to Accumulated Depreciation and Amortization	128
7	Adjustment to Accumulated Deferred Income Taxes	164
8	<b>Total Rate Base Adjustment</b>	<b>\$ (897)</b>
9	<b>Earnings</b>	
10	Adjustment to Amortization and Depreciation Expense	\$ (248)
11	Adjustment to MD Income Tax Expense	20
12	Adjustment to Federal Income Tax Expense	48
13	<b>Total Earnings Adjustment</b>	<b>\$ 180</b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
12 Months Ended September 30, 2025

(Thousands of Dollars)

<u>Line</u>	<u>Adjustment 39 - Removal of NOLC</u>	<u>Adjustment</u>
1	<b>Rate Base</b>	
1	<u>Electric Plant In Service</u>	
2	Removal of Rate Base	\$ (51,509)
3	Adjustment to Maryland electric plant in service	\$ (51,509)
4	<b>Total Rate Base Adjustment</b>	<b><u>\$ (51,509)</u></b>
5	<b>Earnings</b>	
8	Operating expenses	(1,433)
9	<u>Income Taxes</u>	
10	Adjustment to Maryland income tax expense	118
11	Adjustment to Federal income tax expense	276
12	<b>Total Earnings Adjustment</b>	<b><u>\$ 1,039</u></b>

Potomac Electric Power Company

Maryland  
Ratemaking Results - Distribution Only  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Historical Test Year - 12ME Dec. 31, 2024			Bridge Year - 12 ME Dec. 31, 2025			Fully Forecasted Test Year - 12 ME Dec. 31, 2026		
	Average Unadjusted (1)	Ratemaking Adjustments (2)	MD Adjusted (3)	Average Unadjusted (4)	Ratemaking Adjustments (5)	MD Adjusted (6)	Average Unadjusted (7)	Ratemaking Adjustments (8)	MD Adjusted (9)
<b>RATE BASE</b>									
1	\$ 4,905,560	\$ -	\$ 4,905,560	\$ 5,277,014	\$ (91,532)	\$ 5,185,482	\$ 5,603,660	\$ (88,021)	\$ 5,515,639
2	-	-	-	-	-	-	-	-	-
3	5,465	-	5,465	2,073	-	2,073	2,073	-	2,073
4	(1,779,624)	-	(1,779,624)	(1,890,370)	(41,976)	(1,932,346)	(2,026,960)	(43,440)	(2,070,400)
5	3,131,400	-	3,131,400	3,388,716	(133,507)	3,255,209	3,578,772	(131,460)	3,447,312
6	66,541	-	66,541	67,549	-	67,549	69,603	-	69,603
7	10,515	(6,724)	3,791	10,674	(7,656)	3,019	10,999	(8,091)	2,908
8	(689,364)	(42)	(689,405)	(700,961)	(474)	(701,435)	(727,198)	(6,863)	(734,062)
9	101,239	-	101,239	92,364	-	92,364	82,879	-	82,879
10	(37,135)	-	(37,135)	(38,252)	-	(38,252)	(38,252)	-	(38,252)
11	5,966	-	5,966	28,016	-	28,016	39,374	-	39,374
12	23,879	151	24,030	17,115	376	17,491	7,121	20,800	27,921
13	275	-	275	362	-	362	362	-	362
14									
15	<b>\$ 2,613,316</b>	<b>\$ (6,614)</b>	<b>\$ 2,606,702</b>	<b>\$ 2,865,583</b>	<b>\$ (141,261)</b>	<b>\$ 2,724,322</b>	<b>\$ 3,023,661</b>	<b>\$ (125,615)</b>	<b>\$ 2,898,046</b>
<b>OPERATING REVENUE</b>									
16	\$ 795,138	\$ 21,841	\$ 816,979	\$ 820,226	\$ (125)	\$ 820,101	\$ 819,234	\$ 24,573	\$ 843,807
17	9,852	-	9,852	6,792	761	7,553	8,369	-	8,369
18	\$ 804,990	\$ 21,841	\$ 826,831	\$ 827,018	\$ 636	\$ 827,654	\$ 827,603	\$ 24,573	\$ 852,176
19									
<b>OPERATING EXPENSES</b>									
20	\$ 233,403	\$ 10,445	\$ 243,848	\$ 259,166	\$ (24,150)	\$ 235,015	\$ 264,959	\$ (24,062)	\$ 240,898
21	141,043	-	141,043	157,400	(1,852)	155,548	166,929	2,138	169,067
22	222,377	70	222,447	230,728	427	231,155	232,758	606	233,364
23	12,805	947	13,752	9,352	2,496	11,849	7,073	4,087	11,160
24	15,537	2,212	17,749	10,876	5,830	16,706	6,201	9,545	15,746
25									
26	<b>\$ 625,165</b>	<b>\$ 13,674</b>	<b>\$ 638,839</b>	<b>\$ 667,521</b>	<b>\$ (17,249)</b>	<b>\$ 650,273</b>	<b>\$ 677,921</b>	<b>\$ (7,685)</b>	<b>\$ 670,236</b>
27	<b>\$ 179,825</b>	<b>\$ 8,167</b>	<b>\$ 187,992</b>	<b>\$ 159,497</b>	<b>\$ 17,884</b>	<b>\$ 177,381</b>	<b>\$ 149,682</b>	<b>\$ 32,258</b>	<b>\$ 181,940</b>
28	<b>6.88%</b>		<b>7.21%</b>	<b>5.57%</b>		<b>6.51%</b>	<b>4.95%</b>		<b>6.28%</b>
29	2.33%		2.33%	2.87%		2.87%	2.90%		2.90%
30	4.55%		4.88%	2.70%		3.65%	2.05%		3.37%
31	50.50%		50.50%	43.00%		43.00%	43.00%		43.00%
<b>For Informational Purposes Only</b>									
32	<b>9.01%</b>		<b>9.66%</b>	<b>6.28%</b>		<b>8.48%</b>	<b>4.76%</b>		<b>7.84%</b>
33			7.13%			6.18%			6.22%
34			<b>\$ (3,029)</b>			<b>\$ (12,782)</b>			<b>\$ (2,527)</b>
35									<b>7.70%</b>
36									<b>\$ 849,649</b>

Potomac Electric Power Company

Maryland  
Analysis of Revenue Requirement -- Distribution Only  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

	Historical Test Year - 12ME Dec. 31, 2024			Bridge Year - 12 ME Dec. 31, 2025			Fully Forecasted Test Year - 12 ME Dec. 31, 2026		
	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement
Unadjusted amounts	\$ 2,613,316	179,825	\$ 9,078	\$ 2,865,583	159,497	\$ 24,510	\$ 3,023,661	149,682	\$ 53,625
Adjustments									
1 Annualization of Case No. 9702 Revenue	-	15,780	(22,116)	-	(91)	127	-	(86)	120
2 Reflection of FERC 898 Software Functionalization	-	-	-	4,467	(448)	1,015	3,331	(930)	1,594
3 Removal of Q1 2025 Late Payment Charge Pause	-	-	-	-	552	(773)	-	-	-
4 Inclusion of Incremental July 2023 Major Storm Costs	-	-	-	-	-	-	5,371	(1,194)	2,141
5 Reflection of Current Case Costs	-	-	-	-	-	-	-	-	-
6 Reflection of Battery Energy Storage Pilot	-	-	-	-	-	-	137	(45)	75
7 Reflection of EV Phase I Pilot Costs	-	-	-	-	-	-	649	(144)	259
8 Reflection of EV Phase II Pilot Costs	-	-	-	-	-	-	4,022	(815)	1,493
9 Reflection of Smart Inverter Pilot Regulatory Asset	-	-	-	-	-	-	449	(177)	287
10 Reflection of DRIVE Act Regulatory Asset	-	-	-	-	-	-	890	(424)	672
11 Reflection of Supplier Consolidated Billing Costs	-	-	-	-	-	-	3,949	(878)	1,574
12A Reflection of Benning Case No. 9702 Regulatory Asset	109	(12)	28	273	(30)	66	254	(31)	66
12B Reflection of Benning Forecast Costs	-	-	-	-	-	-	608	(64)	143
12C Reflection of Benning Regulatory Asset - Insurance Proceeds	-	-	-	-	-	-	(571)	1,141	(1,649)
13 Reflection of Anacostia Remediation Costs	-	-	-	-	-	-	1,731	(385)	690
14 Removal of Environmental Activity	-	(5,796)	8,123	-	-	-	-	-	-
15 Removal of SERP Expense	-	574	(804)	-	556	(779)	-	542	(759)
16 Removal of Outside Contractors/Legal	-	2	(3)	-	2	(3)	-	2	(3)
17 Removal of Industry Contributions, Membership Fees, and Corporate Jet Costs	-	730	(1,023)	-	730	(1,023)	-	730	(1,023)
18 Exclusion of Executive Incentive Costs	-	1,538	(2,155)	-	1,320	(1,850)	-	1,337	(1,873)
19 Exclusion of 50% Employee Activity Costs	-	358	(501)	-	222	(311)	-	262	(367)
20 Exclusion of Institutional & Promotional Advertising Expense	-	938	(1,314)	-	709	(993)	-	728	(1,020)
21 Inclusion of Commission Authorized Interest Expense	-	(1,305)	1,829	-	(1,240)	1,738	-	(1,240)	1,738
22 Reflection of Uncollectible Write-Offs	-	(4,596)	6,441	-	(849)	1,190	-	(472)	662
23 Adjustments to Cash Working Capital Allowance	(6,724)	-	(672)	(7,656)	-	(663)	(8,091)	-	(705)
24 Tax Effect of Proforma Interest Expense	-	(42)	59	-	(1,114)	1,561	-	(1,004)	1,407
25 Adjustment to Operating Revenues	-	-	-	-	-	-	-	17,840	(25,003)
26 Adjustment to Operating Expenses	-	-	-	-	13,561	(19,006)	-	13,561	(19,006)
27 Ratebase disallowance	-	-	-	(95,937)	2,966	(12,460)	(95,937)	2,966	(12,514)
28 Adjustment to remove NOLC impact	-	-	-	(42,408)	1,039	(5,127)	(42,408)	1,039	(5,150)
<b>Total adjustments</b>	<b>\$ (6,614)</b>	<b>\$ 8,167</b>	<b>\$ (12,107)</b>	<b>\$ (141,261)</b>	<b>\$ 17,884</b>	<b>\$ (37,292)</b>	<b>\$ (125,615)</b>	<b>\$ 32,258</b>	<b>\$ (56,152)</b>
	<b>For Informational Purposes Only</b>			<b>For Informational Purposes Only</b>			<b>For Informational Purposes Only</b>		
<b>Total revenue requirement at requested ROR based on adjusted results</b>	<b>\$ 2,606,702</b>	<b>\$ 187,992</b>	<b>\$ (3,029)</b>	<b>\$ 2,724,322</b>	<b>\$ 177,381</b>	<b>\$ (12,782)</b>	<b>\$ 2,898,046</b>	<b>\$ 181,940</b>	<b>\$ (2,527)</b>

Potomac Electric Power Company

Maryland Ratemaking Adjustments -- Distribution Only  
Fully Forecasted Test Year (FFTY)  
Historical Test Year - 12ME Dec. 31, 2024

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation & Amortization (4)	Other Taxes (5)	MDIT (6)	FIT (7)	Operating Income (8)
1	Annualization of Case No. 9702 Revenue		21,841			70	1,796	4,195	\$ 15,780
2	Reflection of FERC 898 Software Functionalization								\$ -
	Electric Plant in Service	-			-		-	-	
	Accumulated Depreciation and Amortization	-							
	Accumulated Deferred Income Taxes	-							
3	Removal of Q1 2025 Late Payment Charge Pause		-				-	-	\$ -
4	Inclusion of Incremental July 2023 Major Storm Costs			-			-	-	\$ -
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							
5	Reflection of Current Case Costs			-			-	-	\$ -
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							
6	Reflection of Battery Energy Storage Pilot				-		-	-	\$ -
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							
7	Reflection of EV Phase I Pilot Costs				-		-	-	\$ -
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							
8	Reflection of EV Phase II Pilot Costs				-	-	-	-	\$ -
	Electric Plant in Service	-							
	Accumulated Depreciation and Amortization	-							
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							
9	Reflection of Smart Inverter Pilot Regulatory Asset				-		-	-	\$ -
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							
10	Reflection of DRIVE Act Regulatory Asset				-		-	-	\$ -
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							
11	Reflection of Supplier Consolidated Billing Costs				-		-	-	\$ -
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							

Potomac Electric Power Company

Maryland Ratemaking Adjustments -- Distribution Only  
Fully Forecasted Test Year (FFTY)  
Historical Test Year - 12ME Dec. 31, 2024

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation & Amortization (4)	Other Taxes (5)	MDIT (6)	FIT (7)	Operating Income (8)
12A	Reflection of Benning Case No. 9702 Regulatory Asset Regulatory Assets Accumulated Deferred Income Taxes	151 (42)		17			(1)	(3)	\$ (12)
12B	Reflection of Benning Forecast Costs Regulatory Assets Accumulated Deferred Income Taxes	- -		-			-	-	\$ -
12C	Reflection of Benning Regulatory Asset - Insurance Proceeds Regulatory Assets Accumulated Deferred Income Taxes	- -		-			-	-	\$ -
13	Reflection of Anacostia Remediation Costs Regulatory Assets Accumulated Deferred Income Taxes	- -		-			-	-	\$ -
14	Removal of Environmental Activity			7,996			(660)	(1,541)	\$ (5,796)
15	Removal of SERP Expense			(791)			65	152	\$ 574
16	Removal of Outside Contractors/Legal			(3)			0	1	\$ 2
17	Removal of Industry Contributions, Membership Fees, and Corporate Jet Costs			(1,007)			83	194	\$ 730
18	Exclusion of Executive Incentive Costs			(2,122)			175	409	\$ 1,538
19	Exclusion of 50% Employee Activity Costs			(493)			41	95	\$ 358
20	Exclusion of Institutional & Promotional Advertising Expense			(1,294)			107	249	\$ 938
21	Inclusion of Commission Authorized Interest Expense			1,801			(149)	(347)	\$ (1,305)
22	Reflection of Uncollectible Write-Offs			6,341			(523)	(1,222)	\$ (4,596)
23	Adjustments to Cash Working Capital Allowance Cash Working Capital	(6,724)							\$ -
24	Tax Effect of Proforma Interest Expense						13	30	\$ (42)
	<b>Total Ratemaking Adjustments</b>	<b>\$ (6,614)</b>	<b>\$ 21,841</b>	<b>\$ 10,445</b>	<b>\$ -</b>	<b>\$ 70</b>	<b>\$ 947</b>	<b>\$ 2,212</b>	<b>\$ 8,167</b>

Potomac Electric Power Company

Maryland Ratemaking Adjustments -- Distribution Only  
Fully Forecasted Test Year (FFTY)  
Bridge Year - 12 ME Dec. 31, 2025

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation & Amortization (4)	Other Taxes (5)	MDIT (6)	FIT (7)	Operating Income (8)
1	Annualization of Case No. 9702 Revenue		(125)			(0)	(10)	(24)	\$ (91)
2	Reflection of FERC 898 Software Functionalization Electric Plant in Service	4,405			618		(51)	(119)	\$ (448)
	Accumulated Depreciation and Amortization	432							
	Accumulated Deferred Income Taxes	(371)							
3	Removal of Q1 2025 Late Payment Charge Pause		761				63	147	\$ 552
4	Inclusion of Incremental July 2023 Major Storm Costs Regulatory Assets	-		-			-	-	\$ -
	Accumulated Deferred Income Taxes	-							
5	Reflection of Current Case Costs Regulatory Assets	-		-			-	-	\$ -
	Accumulated Deferred Income Taxes	-							
6	Reflection of Battery Energy Storage Pilot Regulatory Assets	-			-		-	-	\$ -
	Accumulated Deferred Income Taxes	-							
7	Reflection of EV Phase I Pilot Costs Regulatory Assets	-			-		-	-	\$ -
	Accumulated Deferred Income Taxes	-							
8	Reflection of EV Phase II Pilot Costs Electric Plant in Service	-			-	-	-	-	\$ -
	Accumulated Depreciation and Amortization	-							
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							
9	Reflection of Smart Inverter Pilot Regulatory Asset Regulatory Assets	-			-		-	-	\$ -
	Accumulated Deferred Income Taxes	-							
10	Reflection of DRIVE Act Regulatory Asset Regulatory Assets	-			-		-	-	\$ -
	Accumulated Deferred Income Taxes	-							
11	Reflection of Supplier Consolidated Billing Costs Regulatory Assets	-			-		-	-	\$ -
	Accumulated Deferred Income Taxes	-							

Potomac Electric Power Company

Maryland Ratemaking Adjustments -- Distribution Only  
Fully Forecasted Test Year (FFTY)  
Bridge Year - 12 ME Dec. 31, 2025

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation & Amortization (4)	Other Taxes (5)	MDIT (6)	FIT (7)	Operating Income (8)
12A	Reflection of Benning Case No. 9702 Regulatory Asset			42			(3)	(8)	\$ (30)
	Regulatory Assets	376							
	Accumulated Deferred Income Taxes	(104)							
12B	Reflection of Benning Forecast Costs			-			-	-	\$ -
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							
12C	Reflection of Benning Regulatory Asset - Insurance Proceeds			-			-	-	\$ -
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							
13	Reflection of Anacostia Remediation Costs			-			-	-	\$ -
	Regulatory Assets	-							
	Accumulated Deferred Income Taxes	-							
14	Removal of Environmental Activity			-			-	-	\$ -
15	Removal of SERP Expense			(767)			63	148	\$ 556
16	Removal of Outside Contractors/Legal			(3)			0	1	\$ 2
17	Removal of Industry Contributions, Membership Fees, and Corporate Jet Costs			(1,007)			83	194	\$ 730
18	Exclusion of Executive Incentive Costs			(1,821)			150	351	\$ 1,320
19	Exclusion of 50% Employee Activity Costs			(306)			25	59	\$ 222
20	Exclusion of Institutional & Promotional Advertising Expense			(978)			81	188	\$ 709
21	Inclusion of Commission Authorized Interest Expense			1,711			(141)	(330)	\$ (1,240)
22	Reflection of Uncollectible Write-Offs			1,172			(97)	(226)	\$ (849)
23	Adjustments to Cash Working Capital Allowance								\$ -
	Cash Working Capital	(7,656)							
24	Tax Effect of Proforma Interest Expense						334	780	\$ (1,114)
25	Adjustment to Operating Revenues								
26	Adjustment to Operating Expenses			(19,137)		428	1,544	3,605	\$ 13,561
27	Ratebase disallowance	(95,937)		(1,621)	(2,470)		338	788	\$ 2,966
28	Adjustment to remove NOLC impact	(42,408)		(1,433)			118	276	\$ 1,039
	<b>Total Ratemaking Adjustments</b>	<b>\$ (141,261)</b>	<b>\$ 636</b>	<b>\$ (24,150)</b>	<b>\$ (1,852)</b>	<b>\$ 427</b>	<b>\$ 2,496</b>	<b>\$ 5,830</b>	<b>\$ 17,884</b>

Potomac Electric Power Company

Maryland Ratemaking Adjustments -- Distribution Only  
Fully Forecasted Test Year (FFTY)  
Fully Forecasted Test Year - 12 ME Dec. 31, 2026

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation & Amortization (4)	Other Taxes (5)	MDIT (6)	FIT (7)	Operating Income (8)
1	Annualization of Case No. 9702 Revenue		(119)			(0)	(10)	(23)	\$ (86)
2	Reflection of FERC 898 Software Functionalization Electric Plant in Service	4,405			1,283		(106)	(247)	\$ (930)
	Accumulated Depreciation and Amortization	(851)							
	Accumulated Deferred Income Taxes	(223)							
3	Removal of Q1 2025 Late Payment Charge Pause		-				-	-	\$ -
4	Inclusion of Incremental July 2023 Major Storm Costs Regulatory Assets	7,410		1,647			(136)	(317)	\$ (1,194)
	Accumulated Deferred Income Taxes	(2,039)							
5	Reflection of Current Case Costs Regulatory Assets	-		-			-	-	\$ -
	Accumulated Deferred Income Taxes	-							
6	Reflection of Battery Energy Storage Pilot Regulatory Assets	189			62		(5)	(12)	\$ (45)
	Accumulated Deferred Income Taxes	(52)							
7	Reflection of EV Phase I Pilot Costs Regulatory Assets	895			199		(16)	(38)	\$ (144)
	Accumulated Deferred Income Taxes	(246)							
8	Reflection of EV Phase II Pilot Costs Electric Plant in Service	3,511			1,025	100	(93)	(217)	\$ (815)
	Accumulated Depreciation and Amortization	(181)							
	Regulatory Assets	2,218							
	Accumulated Deferred Income Taxes	(1,527)							
9	Reflection of Smart Inverter Pilot Regulatory Asset Regulatory Assets	620			244		(20)	(47)	\$ (177)
	Accumulated Deferred Income Taxes	(171)							
10	Reflection of DRIVE Act Regulatory Asset Regulatory Assets	1,227			585		(48)	(113)	\$ (424)
	Accumulated Deferred Income Taxes	(338)							
11	Reflection of Supplier Consolidated Billing Costs Regulatory Assets	5,449			1,211		(100)	(233)	\$ (878)
	Accumulated Deferred Income Taxes	(1,499)							

Potomac Electric Power Company

Maryland Ratemaking Adjustments -- Distribution Only  
Fully Forecasted Test Year (FFTY)  
Fully Forecasted Test Year - 12 ME Dec. 31, 2026

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation & Amortization (4)	Other Taxes (5)	MDIT (6)	FIT (7)	Operating Income (8)
12A	Reflection of Benning Case No. 9702 Regulatory Asset			43			(4)	(8)	\$ (31)
	Regulatory Assets	351							
	Accumulated Deferred Income Taxes	(96)							
12B	Reflection of Benning Forecast Costs			88			(7)	(17)	\$ (64)
	Regulatory Assets	839							
	Accumulated Deferred Income Taxes	(231)							
12C	Reflection of Benning Regulatory Asset - Insurance Proceeds			(1,575)			130	303	\$ 1,141
	Regulatory Assets	(787)							
	Accumulated Deferred Income Taxes	217							
13	Reflection of Anacostia Remediation Costs			531			(44)	(102)	\$ (385)
	Regulatory Assets	2,388							
	Accumulated Deferred Income Taxes	(657)							
14	Removal of Environmental Activity			-			-	-	\$ -
15	Removal of SERP Expense			(747)			62	144	\$ 542
16	Removal of Outside Contractors/Legal			(3)			0	1	\$ 2
17	Removal of Industry Contributions, Membership Fees, and Corporate Jet Costs			(1,007)			83	194	\$ 730
18	Exclusion of Executive Incentive Costs			(1,844)			152	355	\$ 1,337
19	Exclusion of 50% Employee Activity Costs			(361)			30	70	\$ 262
20	Exclusion of Institutional & Promotional Advertising Expense			(1,004)			83	194	\$ 728
21	Inclusion of Commission Authorized Interest Expense			1,711			(141)	(330)	\$ (1,240)
22	Reflection of Uncollectible Write-Offs			652			(54)	(126)	\$ (472)
23	Adjustments to Cash Working Capital Allowance								\$ -
	Cash Working Capital	(8,091)							
24	Tax Effect of Proforma Interest Expense						301	703	\$ (1,004)
25	Adjustment to Operating Revenues		24,692			79	2,031	4,742	17,840
26	Adjustment to Operating Expenses			(19,137)		428	1,544	3,605	13,561
27	Ratebase disallowance	(95,937)		(1,621)	(2,470)		338	788	2,966
28	Adjustment to remove NOLC impact	(42,408)		(1,433)			118	276	1,039
	<b>Total Ratemaking Adjustments</b>	<b>\$ (125,615)</b>	<b>\$ 24,573</b>	<b>\$ (24,062)</b>	<b>\$ 2,138</b>	<b>\$ 606</b>	<b>\$ 4,087</b>	<b>\$ 9,545</b>	<b>\$ 32,258</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 1 - Annualization of Case No. 9702 Revenue	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Adjustment to annualize billed distribution revenues to levels set in Case No. 9702	\$ 21,841	\$ (125)	\$ (119)
3	Adjustment to Other Taxes (PSC assessment)	70	(0)	(0)
4	Adjustment to Maryland Income Tax expense	1,796	(10)	(10)
5	Adjustment to Federal Income Tax expense	4,195	(24)	(23)
6	<b>Total Earnings</b>	<b>\$ 15,780</b>	<b>\$ (91)</b>	<b>\$ (86)</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 2 - Reflection of FERC 898 Software Functionalization	Historical Test Year		Bridge Year	FFTY
		12 ME Dec 31, 2024		12 ME Dec 31, 2025	12 ME Dec 31, 2026
1	<b>Earnings</b>				
2	Adjustment to Depreciation & Amortization Expense	\$ -	\$	618	\$ 1,283
3	Adjustment to Maryland Income Tax expense	-		(51)	(106)
4	Adjustment to Federal Income Tax expense	-		(119)	(247)
5	<b>Total Earnings</b>	<b>\$ -</b>	<b>\$</b>	<b>(448)</b>	<b>\$ (930)</b>
6	<b>Rate Base</b>				
7	Adjustment to Electric Plant in Service	\$ -	\$	4,405	\$ 4,405
8	Adjustment to Accumulated Depreciation & Amortization	-		432	(851)
9	Adjustment to accumulated deferred income taxes	-		(371)	(223)
10	<b>Total Rate Base</b>	<b>\$ -</b>	<b>\$</b>	<b>4,467</b>	<b>\$ 3,331</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 3 - Removal of Q1 2025 Late Payment Charge Pause	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	CY24 Pepco MD Late Payment Charge Revenues	-	2,621	-
3	Normalized Quarterly LPC Revenue	-	655	-
4	Q1 2025 LPC Revenue	-	(106)	-
5	Adjustment to Other Revenue	-	761	-
6	Adjustment to MD income tax expense	-	63	-
7	Adjustment to Federal income tax expense	-	147	-
8	<b>Total Earnings</b>	<b>\$ -</b>	<b>\$ 552</b>	<b>\$ -</b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 4 - Inclusion of Incremental July 2023 Major Storm Costs	Historical Test Year	Bridge Year	FFTY
		12 ME Dec 31, 2024	12 ME Dec 31, 2025	12 ME Dec 31, 2026
1	<b>Earnings</b>			
2	July 2023 Major Storm Deferred Costs	\$ -	\$ -	\$ 8,234
3	Adjustment to O&M for Amortization Expense (5 year amortization period)	-	-	1,647
4	Adjustment to MD income tax expense	-	-	(136)
5	Adjustment to federal income tax expense	-	-	(317)
6	<b>Total Earnings</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ (1,194)</b>
7	<b>Rate Base</b>			
8	Beginning MD Regulatory Asset Balance	\$ -	\$ -	\$ 8,234
9	Amortization Expense	-	-	1,647
10	Ending MD Regulatory Asset Balance	-	-	6,587
11	Adjustment to regulatory assets	-	-	7,410
12	Adjustment to accumulated deferred income taxes	-	-	(2,039)
13	<b>Total Rate Base</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 5,371</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 5 - Reflection of Current Case Costs	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Current Rate Case Costs Estimate			
3	Adjustment to O&M for Amortization Expense (3 year amortization period)	\$ -	\$ -	\$ -
4	Adjustment to Maryland Income Tax expense	-	-	-
5	Adjustment to Federal Income Tax expense	-	-	-
6	<b>Total Earnings</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>
7	<b>Rate Base</b>			
8	Average MD regulatory asset balance	\$ -		
9	Decline in balance After Year 1		-	
10	Total average unamortized rate base balances	\$ -	\$ -	\$ -
11	Adjustment to accumulated deferred income taxes	-	-	-
12	Adjustment to rate base, net of accumulated deferred taxes	\$ -	\$ -	\$ -
13	<b>Total Rate Base</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 6 - Reflection of Battery Energy Storage Pilot	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Battery Energy Storage Costs - MD Distribution	\$ -	\$ 130	\$ 180
3	Adjustment to Amortization Expense (5 Year Amortization Period)	-	-	62
4	Adjustment to MD income tax expense	-	-	(5)
5	Adjustment to federal income tax expense	-	-	(12)
6	<b>Total Earnings</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ (45)</u>
7	<b>Rate Base</b>			
8	Average Regulatory Asset Balance	-	-	220
9	Average Accumulated Amortization	-	-	(31)
10	Adjustment to Regulatory Assets	\$ -	\$ -	\$ 189
11	Adjustment to accumulated deferred income taxes	-	-	(52)
12	<b>Total Rate Base</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 137</u>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 7 - Reflection of EV Phase I Pilot Costs	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Forecast Program Costs		\$ 995	
3	Adjustment to MD distribution amortization expense (5 year)	\$ -	\$ -	\$ 199
4	Adjustment to Maryland Income Tax expense	-	-	(16)
5	Adjustment to Federal Income Tax expense	-	-	(38)
6	<b>Total Earnings</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ (144)</u>
7	<b>Rate Base</b>			
8	Average Regulatory Asset Balance		-	995
9	Average Accumulated Amortization	-	-	(99)
10	Adjustment to Regulatory Assets	\$ -	\$ -	\$ 895
11	Adjustment to accumulated deferred income taxes	-	-	(246)
12	<b>Total Rate Base</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 649</u>

Potomac Electric Power Company

Maryland Distribution  
Rate-making Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 8 - Reflection of EV Phase II Pilot Costs	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Adjustment to Depreciation & Amortization Expense	\$ -	\$ -	\$ 1,025
3	Adjustment to Other Taxes	-	-	100
4	Adjustment to Maryland Income Tax expense	-	-	(93)
5	Adjustment to Federal Income Tax expense	-	-	(217)
6	<b>Total Earnings</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ (815)</u>
7	<b>Rate Base</b>			
8	Adjustment to Electric Plant in Service	\$ -	\$ -	\$ 3,511
9	Adjustment to Accumulated Depreciation & Amortization	-	-	(181)
10	Adjustment to Regulatory Assets	-	-	2,218
11	Adjustment to accumulated deferred income taxes	-	-	(1,527)
12	<b>Total Rate Base</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 4,022</u>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 9 - Reflection of Smart Inverter Pilot Regulatory Asset	Historical Test Year	Bridge Year	FFTY
		12 ME Dec 31, 2024	12 ME Dec 31, 2025	12 ME Dec 31, 2026
1	<b>Earnings</b>			
2	Incremental Smart Inverter Pilot Costs	\$ -	\$ 266	\$ 952
3	Cumulative Smart Inverter Pilot Costs	-	266	1,218
4	Adjustment to Amortization Expense (5 Year Amortization Period)	-	-	244
5	Adjustment to MD income tax expense	-	-	(20)
6	Adjustment to federal income tax expense	-	-	(47)
7	<b>Total Earnings</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ (177)</u>
8	<b>Rate Base</b>			
9	Average Regulatory Asset Balance	-	-	742
10	Average Accumulated Amortization	-	-	(122)
11	Adjustment to Regulatory Assets	\$ -	\$ -	\$ 620
12	Adjustment to accumulated deferred income taxes	-	-	(171)
13	<b>Total Rate Base</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 449</u>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 10 - Reflection of DRIVE Act Regulatory Asset	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Incremental DRIVE Act Program Costs	\$ -	\$ 114	\$ 2,813
3	Cumulative DRIVE Act Program Costs	-	114	2,927
4	Adjustment to Amortization Expense (5 Year Amortization Period)	-	-	585
5	Adjustment to MD income tax expense	-	-	(48)
6	Adjustment to federal income tax expense	-	-	(113)
7	<b>Total Earnings</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ (424)</u>
8	<b>Rate Base</b>			
9	Average Regulatory Asset Balance	-	-	1,520
10	Average Accumulated Amortization	-	-	(293)
11	Adjustment to Regulatory Assets	\$ -	\$ -	\$ 1,227
12	Adjustment to accumulated deferred income taxes	-	-	(338)
13	<b>Total Rate Base</b>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 890</u>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 11 - Reflection of Supplier Consolidated Billing Costs	Historical Test Year 12 ME Dec 31, 2024	Bridge Year 12 ME Dec 31, 2025	FFTY 12 ME Dec 31, 2026
1	<b>Earnings</b>			
2	Actual Supplier Consolidated Billing Costs	7,189		
3	Distribution Allocator	84.21%		
4	Supplier Consolidated Billing Costs - Distribution	6,054		
5	Adjustment to Amortization Expense (5 Year Amortization Period)	-	-	1,211
6	Adjustment to MD income tax expense	-	-	(100)
7	Adjustment to federal income tax expense	-	-	(233)
8	<b>Total Earnings</b>	\$ -	\$ -	\$ (878)
9	<b>Rate Base</b>			
10	Beginning Regulatory Asset Balance	-	-	6,054
11	Decline in Average Regulatory Asset Balance	-	-	(605)
12	Adjustment to Regulatory Assets	\$ -	\$ -	\$ 5,449
13	Adjustment to accumulated deferred income taxes	-	-	(1,499)
14	<b>Total Rate Base</b>	\$ -	\$ -	\$ 3,949

Potomac Electric Power Company

Maryland Distribution  
Rate-making Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 12A - Reflection of Benning Case No. 9702 Regulatory Asset	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Adjustment to O&M for Amortization Expense (10 year amortization period)	17	42	43
3	Adjustment to Maryland income tax expense	(1)	(3)	(4)
4	Adjustment to federal income tax expense	(3)	(8)	(8)
5	<b>Total Earnings</b>	<u>\$ (12)</u>	<u>\$ (30)</u>	<u>\$ (31)</u>
6	<b>Rate Base</b>			
7	Total average unamortized rate base balance	\$ 151	\$ 376	\$ 351
8	Adjustment to accumulated deferred income taxes	(42)	(104)	(96)
9	<b>Total Rate Base</b>	<u>\$ 109</u>	<u>\$ 273</u>	<u>\$ 254</u>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 12B - Reflection of Benning Forecast Costs	Historical Test Year		Bridge Year		FFTY	
		<u>12 ME Dec 31, 2024</u>		<u>12 ME Dec 31, 2025</u>		<u>12 ME Dec 31, 2026</u>	
1	<b>Earnings</b>						
2	Future Costs for RI/FS - Pepco (April 2025 - December 2026)	\$	-	\$	638	\$	2,900
3	Maryland Allocation Factor - Benning Allocator		42.3%		42.3%		42.3%
4	Future Costs for RI/FS - Pepco (Apr-25 - Dec-26) - Maryland	\$	-	\$	270	\$	1,227
5	Adjustment to Amortization Expense (10 year amortization period)	\$	-	\$	-	\$	88
6	Adjustment to MD income tax expense		-		-		(7)
7	Adjustment to federal income tax expense		-		-		(17)
8	<b>Total Earnings</b>	<u>\$</u>	<u>-</u>	<u>\$</u>	<u>-</u>	<u>\$</u>	<u>(64)</u>
9	<b>Rate Base</b>						
10	Average regulatory asset - Pepco MD	\$	-	\$	-	\$	883
11	Average accumulated amortization		-		-		(44)
12	Average Rate Base	\$	-	\$	-	\$	839
13	Adjustment to accumulated deferred income taxes		-		-		(231)
14	<b>Total Rate Base</b>	<u>\$</u>	<u>-</u>	<u>\$</u>	<u>-</u>	<u>\$</u>	<u>608</u>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 12C - Reflection of Benning Regulatory Asset - Insurance Proceeds	Historical Test Year 12 ME Dec 31, 2024	Bridge Year 12 ME Dec 31, 2025	FFTY 12 ME Dec 31, 2026
1	<b>Earnings</b>			
2	Available Benning insurance proceeds	\$ (3,722)		
3	Benning costs approved in CN 9702	42.30%		
4	Allocation factor - Maryland (Benning Allocator)	\$ (1,575)		
5	Adjustment to O&M for Amortization Expense (1 year amortization period)	\$ -	\$ -	\$ (1,575)
6	Adjustment to Maryland Income Tax expense	-	-	130
7	Adjustment to Federal Income Tax expense	-	-	303
8	<b>Total Earnings</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 1,141</b>
9	<b>Rate Base</b>			
10	Average MD regulatory asset balance	\$ (1,575)		
11	Change in balance After Year 1	787		
12	Total average unamortized rate base balances	\$ (787)		
13	Average Unamortized Regulatory Asset Balance	-	-	(787)
14	Adjustment to accumulated deferred income taxes	-	-	217
15	<b>Total Rate Base</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ (571)</b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 13 - Reflection of Anacostia Remediation Costs	Historical Test Year 12 ME Dec 31, 2024	Bridge Year 12 ME Dec 31, 2025	FFTY 12 ME Dec 31, 2026
1	<b>Anacostia Insurance Proceeds</b>			
2	Available Anacostia insurance proceeds	12,573		
3	Allocation to MD - STDPLT Allocation	48.6%		
4	MD allocated Anacostia insurance proceeds	<b>\$ 6,107</b>		
5	<b>ARSP Costs</b>			
6	Incremental ARSP Costs - DOEE Payment for Clean Land Fund	\$ -	\$ 11,750	\$ 11,750
7	Allocation to MD - STDPLT Allocation	48.6%	48.6%	48.6%
8	Incremental Pepco MD Allocated Cost	-	5,708	5,708
9	Available Anacostia Insurance Proceeds	6,107	6,107	400
10	Incremental Pepco MD Allocated Cost Net of Insurance Proceeds	-	-	5,308
11	Cumulative Pepco MD Allocated Cost Net of Insurance Proceeds	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 5,308</b>
12	<b>Earnings</b>			
13	Adjustment to O&M for Amortization Expense (10 year amortization period)	-	-	531
14	Adjustment to state income tax expense	-	-	(44)
15	Adjustment to federal income tax expense	-	-	(102)
16	<b>Total Earnings</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ (385)</b>
17	<b>Rate Base</b>			
18	Average Regulatory Asset Balance	\$ -	\$ -	\$ 2,654
19	Average Accumulated Amortization	\$ -	\$ -	\$ (265)
20	Adjustment to Regulatory Assets	-	-	2,388
21	Adjustment to accumulated deferred income taxes	-	-	(657)
22	<b>Total Rate Base</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 1,731</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 14 - Removal of Environmental Activity	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Total distribution-related charge for Benning environmental accrual included in Distribution O&M	\$ (4,466)	\$ -	\$ -
3	Allocation to MD - Benning Allocation	42.30%	42.30%	42.30%
4	Total distribution-related charge for Anacostia environmental liability true-up included in Distribution O&M	\$ (12,573)	\$ -	\$ -
5	Allocation to MD - STDPLT Allocation	48.57%	48.57%	48.57%
6	Adjustment to MD O&M Expense	7,996	-	-
7	Adjustment to state income tax expense	(660)	-	-
8	Adjustment to federal income tax expense	(1,541)	-	-
9	<b>Total Earnings</b>	<b>\$ (5,796)</b>	<b>\$ -</b>	<b>\$ -</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 15 - Removal of SERP Expense	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Total distribution SERP expense	\$ 1,369	\$ 1,327	\$ 1,292
3	Allocation to Maryland (O&M less A&G ratio)	57.83%	57.83%	57.83%
4	Remove Maryland distribution SERP expense	\$ (791)	\$ (767)	\$ (747)
5	Adjustment to Maryland Income Tax expense	65	63	62
6	Adjustment to Federal Income Tax expense	152	148	144
7	<b>Total Earnings</b>	<u>\$ 574</u>	<u>\$ 556</u>	<u>\$ 542</u>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 16 - Removal of Outside Contractors/Legal	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Removal of certain outside legal expenses	\$ 7	\$ 7	\$ 7
3	Allocation factor - distribution (labor ratio)	84.21%	84.21%	84.21%
4	Distribution portion of removal of outside legal costs	\$ 6	\$ 6	\$ 6
5	Allocation to MD (O&M less A&G and Storm Costs ratio)	57.83%	57.83%	57.83%
6	Adjustment to Maryland O&M expense to remove certain outside legal expense	(3)	(3)	(3)
7	Adjustment to Maryland income tax expense	0	0	0
8	Adjustment to federal income tax expense	1	1	1
9	<b>Total Earnings</b>	<b>\$ 2</b>	<b>\$ 2</b>	<b>\$ 2</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 17 - Removal of Industry Contributions, Membership Fees, and Corporate Jet Costs	Historical Test Year	Bridge Year	FFTY
		12 ME Dec 31, 2024	12 ME Dec 31, 2025	12 ME Dec 31, 2026
1	<b>Earnings</b>			
2	Industry Association Dues	\$ 541	\$ 541	\$ 541
3	Corporate Jet Costs	1,527	1,527	1,527
4	Allocation to Distribution (Labor Ratio)	84.21%	84.21%	84.21%
5	Excludable industry dues & corporate jet costs included in distribution O&M	1,742	1,742	1,742
6	Allocation to M.D. (O&M less A&G ratio and storms)	57.83%	57.83%	57.83%
7	Adjustment to M.D. operations and maintenance expense	(1,007)	(1,007)	(1,007)
8	Adjustment to M.D. income tax expense	83	83	83
9	Adjustment to Federal income tax expense	194	194	194
10	<b>Total Earnings</b>	<b>\$ 730</b>	<b>\$ 730</b>	<b>\$ 730</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 18 - Exclusion of Executive Incentive Costs	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Distribution-related executive incentive costs to remove from O&M expense	\$ 3,081	\$ 2,834	\$ 2,854
3	Adjustment to remove earnings-related CEO EIP expense	\$ 60	\$ 20	\$ 24
4	Adjustment to remove earnings-related Exelon CEO & direct report	\$ 527	\$ 295	\$ 311
5	Distribution-related incentive costs in Pepco O&M expense	\$ 3,669	\$ 3,150	\$ 3,189
6	Allocation to Maryland (O&M less A&G ratio)	57.83%	57.83%	57.83%
7	Maryland allocated executive incentive costs	\$ 2,122	\$ 1,821	\$ 1,844
8	Adjustment to Maryland O&M expense to remove allocated	\$ (2,122)	\$ (1,821)	\$ (1,844)
9	Adjustment to Maryland Income Tax expense	175	150	152
10	Adjustment to Federal Income Tax expense	409	351	355
11	<b>Total Earnings</b>	<b>\$ 1,538</b>	<b>\$ 1,320</b>	<b>\$ 1,337</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 19 - Exclusion of 50% Employee Activity Costs	Historical Test Year		Bridge Year		FFTY	
		<u>12 ME Dec 31, 2024</u>		<u>12 ME Dec 31, 2025</u>		<u>12 ME Dec 31, 2026</u>	
1	<b>Earnings</b>						
2	Total distribution employee activity costs incurred in test period	\$	1,706	\$	1,060	\$	1,248
3	Allocation to Maryland (O&M less A&G ratio)		57.83%		57.83%		57.83%
4	Maryland distribution O&M expense	\$	987	\$	613	\$	722
5	Remove Maryland distribution O&M expense - employee activity costs	\$	(987)	\$	(613)	\$	(722)
6	Exclusion of 50% per Order No. 85724		50%		50%		50%
7	Adjustment to Maryland distribution O&M expense	\$	(493)	\$	(306)	\$	(361)
8	Adjustment to Maryland Income Tax expense		41		25		30
9	Adjustment to Federal Income Tax expense		95		59		70
10	<b>Total Earnings</b>	<b>\$</b>	<b>358</b>	<b>\$</b>	<b>222</b>	<b>\$</b>	<b>262</b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 20 - Exclusion of Institutional & Promotional Advertising Expense	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Institutional and promotional advertising expenses (Acct 930.1 and Other)	\$ 2,237	\$ 1,691	\$ 1,737
3	Allocation to Maryland (O&M less A&G ratio)	57.83%	57.83%	57.83%
4	MD allocated institutional advertising (Acct 930.1 and Other)	\$ 1,294	\$ 978	\$ 1,004
5	Adjustment to Maryland O&M expense to remove institutional advertising	(1,294)	(978)	(1,004)
6	Adjustment to Maryland Income Tax expense	107	81	83
7	Adjustment to Federal Income Tax expense	249	188	194
8	<b>Total Earnings</b>	<b>\$ 938</b>	<b>\$ 709</b>	<b>\$ 728</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 21 - Inclusion of Commission Authorized Interest Expense	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Interest on customer deposits at 4.19%	\$ 1,531	\$ 1,445	\$ 1,445
3	Credit facility costs (quarterly maintenance fee)	553	547	547
4	Allocation to Distribution (Labor ratio)	84.21%	84.21%	84.21%
5	Distribution-related credit facility costs	466	460	460
6	Allocation factor - Maryland (O&M less A&G ratio and storms)	57.83%	57.83%	57.83%
7	Maryland allocated credit facility costs	269	266	266
8	Adjustment to include Commission-allowed interest charges in distribution O&M expense	\$ 1,801	\$ 1,711	\$ 1,711
9	Adjustment to Maryland income tax expense	(149)	(141)	(141)
10	Adjustment to Federal income tax expense	(347)	(330)	(330)
11	<b>Total Earnings</b>	<b>\$ (1,305)</b>	<b>\$ (1,240)</b>	<b>\$ (1,240)</b>

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 22 - Reflection of Uncollectible Write-Offs	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Maryland distribution-related uncollectible write-offs, net of	\$ 10,982	\$ 7,839	\$ 7,744
3	Maryland distribution-related uncollectible accrued expense	\$ 4,641	\$ 6,668	\$ 7,092
4	Adjustment to Maryland distribution O&M expense to reflect net	\$ 6,341	\$ 1,172	\$ 652
5	Adjustment to Maryland Income Tax expense	(523)	(97)	(54)
6	Adjustment to Federal Income Tax expense	(1,222)	(226)	(126)
7	<b>Total Earnings</b>	<b><u>\$ (4,596)</u></b>	<b><u>\$ (849)</u></b>	<b><u>\$ (472)</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
 Ratemaking Adjustment Calculation  
 Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 23 - Adjustments to Cash Working Capital Allowance	Historical Test Year 12 ME Dec 31, 2024	Bridge Year 12 ME Dec 31, 2025	FFTY 12 ME Dec 31, 2026
1	<b>Rate Base</b>			
2	Reflection of lag on interest expense	\$ (6,909)	\$ (7,588)	\$ (8,048)
3	Impact of proforma ratemaking adjustments on cash working capital	185	(68)	(43)
4	Adjustment to cash working capital allowance	(6,724)	(7,656)	(8,091)
5	<b>Total Rate Base</b>	<b>\$ (6,724)</b>	<b>\$ (7,656)</b>	<b>\$ (8,091)</b>

Potomac Electric Power Company

Summary of Unadjusted Results and Ratemaking Adjustments for Cash Working Capital  
Fully Forecasted Test Year (FFTY)

Adjustment 23 - Adjustments to Cash Working Capital Allowance

(1) LINE NO.	(2)	(3) ITEM	Historical Test Year - 12 ME Dec 31, 2024							
			(4) REVENUE	(5) O&M	(6) DEPR/ AMORT	(7) OTHER TAXES	(8) SIT	(9) FIT	(10) TOTAL EXPENSE	(11) RATE BASE
1		Maryland Unadjusted Results	\$ 804,990	\$ 233,403	\$ 141,043	\$ 222,377	\$ 12,805	\$ 15,537	\$ 625,165	\$ 2,613,316
		Ratemaking Adjustments								
1	1	Annualization of Case No. 9702 Revenue	21,841	-	-	70	1,796	4,195	6,061	-
2	2	Reflection of FERC 898 Software Functionalization	-	-	-	-	-	-	-	-
3	3	Removal of Q1 2025 Late Payment Charge Pause	-	-	-	-	-	-	-	-
4	4	Inclusion of Incremental July 2023 Major Storm Costs	-	-	*	-	-	-	-	-
5	5	Reflection of Current Case Costs	-	-	*	-	-	-	-	-
6	6	Reflection of Battery Energy Storage Pilot	-	-	*	-	-	-	-	-
7	7	Reflection of EV Phase I Pilot Costs	-	-	-	-	-	-	-	-
8	8	Reflection of EV Phase II Pilot Costs	-	-	-	-	-	-	-	-
9	9	Reflection of Smart Inverter Pilot Regulatory Asset	-	-	-	-	-	-	-	-
10	10	Reflection of DRIVE Act Regulatory Asset	-	-	-	-	-	-	-	-
11	11	Reflection of Supplier Consolidated Billing Costs	-	-	-	-	-	-	-	-
12	12A	Reflection of Benning Case No. 9702 Regulatory Asset	-	17	*	-	(1)	(3)	12	109
13	12B	Reflection of Benning Forecast Costs	-	-	*	-	-	-	-	-
14	12C	Reflection of Benning Regulatory Asset - Insurance Proceeds	-	-	*	-	-	-	-	-
15	13	Reflection of Anacostia Remediation Costs	-	-	*	-	-	-	-	-
16	14	Removal of Environmental Activity	-	7,996	-	-	(660)	(1,541)	5,796	-
17	15	Removal of SERP Expense	-	(791)	-	-	65	152	(574)	-
18	16	Removal of Outside Contractors/Legal	-	(3)	-	-	0	1	(2)	-
19	17	Removal of Industry Contributions, Membership Fees, and Corporate Jet Costs	-	(1,007)	-	-	83	194	(730)	-
20	18	Exclusion of Executive Incentive Costs	-	(2,122)	-	-	175	409	(1,538)	-
21	19	Exclusion of 50% Employee Activity Costs	-	(493)	-	-	41	95	(358)	-
22	20	Exclusion of Institutional & Promotional Advertising Expense	-	(1,294)	-	-	107	249	(938)	-
23	21	Inclusion of Commission Authorized Interest Expense	-	1,801	-	-	(149)	(347)	1,305	-
24	22	Reflection of Uncollectible Write-Offs	-	6,341	-	-	(523)	(1,222)	4,596	-
25		Proforma Interest Expense							60,931	
26		Cash Working Capital Ratio							-11.34%	
27		<b>Interest Expense Lag</b>							<b>\$ (6,909)</b>	
28		<b>Subtotal Ratemaking Adjustments</b>	<b>\$ 21,841</b>	<b>\$ 10,445</b>	<b>\$ -</b>	<b>\$ 70</b>	<b>\$ 934</b>	<b>\$ 2,182</b>		<b>\$ 2,613,426</b>
29		Less: Non-Cash or Expense Not Lagged in CWC *		(17)						
30		Subtotal Ratemaking Adjustments with CWC Impact	\$ 21,841	\$ 10,428	\$ -	\$ 70	\$ 934	\$ 2,182		
31		Cash Working Capital Ratio		2.61%	0.00%	2.18%	-2.82%	-2.82%		
32		<b>Proforma Impact to Cash Working Capital of RMA Nos. 1-21</b>	<b>\$ -</b>	<b>\$ 272</b>	<b>\$ -</b>	<b>\$ 2</b>	<b>\$ (26)</b>	<b>\$ (62)</b>		
33		Tax Effect of Proforma Interest					\$ 1,483	\$ 3,463		
34		Cash Working Capital Ratio					0.00%	0.00%		
35		<b>Proforma Impact</b>					<b>\$ -</b>	<b>\$ -</b>		
36		Adjusted rate base before proforma adjustments	\$ 2,613,426	\$ 2,613,426	\$ 2,606,702					
37		Plus: Impact of Interest Expense Lag		(6,909)						
38		Plus: Impact of RMA Nos. 1-21		185						
39		Plus: Impact Interest Synchronization			-					
40		Average Rate Base for Interest Synchronization	\$ 2,613,426	\$ 2,606,702	\$ 2,606,702					
41		Weighted cost of long term debt	2.33%	2.33%	2.33%					
42		Pro-forma interest	\$ 60,931	\$ 60,774	\$ 60,774					
43		Less: Per book interest expense		(78,750)	(60,774)					
44		Change to interest expense		\$ (17,976)	\$ -					
45		Adjustment to Maryland Income Tax		\$ 1,483	\$ -					
46		Adjustment to Federal Income Tax		\$ 3,463	\$ -					

Potomac Electric Power Company

Summary of Unadjusted Results and Ratemaking Adjustments for Cash Working Capital  
Fully Forecasted Test Year (FFTY)

Adjustment 23 - Adjustments to Cash Working Capital Allowance

			Bridge Year - 12 ME Dec 31, 2025							
(1) LINE NO.	(2)	(3) ITEM	(12) REVENUE	(13) O&M	(14) DEPR/ AMORT	(15) OTHER TAXES	(16) SIT	(17) FIT	(18) TOTAL EXPENSE	(19) RATE BASE
1		Maryland Unadjusted Results	\$ 827,018	\$ 259,166	\$ 157,400	\$ 230,728	\$ 9,352	\$ 10,876	\$ 667,521	\$ 2,865,583
		Ratemaking Adjustments								
1	1	Annualization of Case No. 9702 Revenue	(125)	-	-	(0)	(10)	(24)	(35)	-
2	2	Reflection of FERC 898 Software Functionalization	-	-	618	-	(51)	(119)	448	4,467
3	3	Removal of Q1 2025 Late Payment Charge Pause	761	-	-	-	63	147	209	-
4	4	Inclusion of Incremental July 2023 Major Storm Costs	-	-	*	-	-	-	-	-
5	5	Reflection of Current Case Costs	-	-	*	-	-	-	-	-
6	6	Reflection of Battery Energy Storage Pilot	-	-	*	-	-	-	-	-
7	7	Reflection of EV Phase I Pilot Costs	-	-	-	-	-	-	-	-
8	8	Reflection of EV Phase II Pilot Costs	-	-	-	-	-	-	-	-
9	9	Reflection of Smart Inverter Pilot Regulatory Asset	-	-	-	-	-	-	-	-
10	10	Reflection of DRIVE Act Regulatory Asset	-	-	-	-	-	-	-	-
11	11	Reflection of Supplier Consolidated Billing Costs	-	-	-	-	-	-	-	-
12	12A	Reflection of Benning Case No. 9702 Regulatory Asset	-	42	*	-	(3)	(8)	30	273
13	12B	Reflection of Benning Forecast Costs	-	-	*	-	-	-	-	-
14	12C	Reflection of Benning Regulatory Asset - Insurance Proceeds	-	-	*	-	-	-	-	-
15	13	Reflection of Anacostia Remediation Costs	-	-	*	-	-	-	-	-
16	14	Removal of Environmental Activity	-	-	-	-	-	-	-	-
17	15	Removal of SERP Expense	-	(767)	-	-	63	148	(556)	-
18	16	Removal of Outside Contractors/Legal	-	(3)	-	-	0	1	(2)	-
19	17	Removal of Industry Contributions, Membership Fees, and Corporate Jet Cost	-	(1,007)	-	-	83	194	(730)	-
20	18	Exclusion of Executive Incentive Costs	-	(1,821)	-	-	150	351	(1,320)	-
21	19	Exclusion of 50% Employee Activity Costs	-	(306)	-	-	25	59	(222)	-
22	20	Exclusion of Institutional & Promotional Advertising Expense	-	(978)	-	-	81	188	(709)	-
23	21	Inclusion of Commission Authorized Interest Expense	-	1,711	-	-	(141)	(330)	1,240	-
24	22	Reflection of Uncollectible Write-Offs	-	1,172	-	-	(97)	(226)	849	-
25		Proforma Interest Expense							66,920	
26		Cash Working Capital Ratio							-11.34%	
27		<b>Interest Expense Lag</b>							<b>\$ (7,588)</b>	
28		<b>Subtotal Ratemaking Adjustments</b>	<b>\$ 636</b>	<b>\$ (1,959)</b>	<b>\$ 618</b>	<b>\$ (0)</b>	<b>\$ 163</b>	<b>\$ 381</b>		<b>\$ 2,870,323</b>
29		Less: Non-Cash or Expense Not Lagged in CWC *		(42)						
30		Subtotal Ratemaking Adjustments with CWC Impact	\$ 636	\$ (2,001)	\$ 618	\$ (0)	\$ 163	\$ 381		
31		Cash Working Capital Ratio		2.61%		2.18%	-2.82%	-2.82%		
32		<b>Proforma Impact to Cash Working Capital of RMA Nos. 1-21</b>	<b>\$ -</b>	<b>\$ (52)</b>	<b>\$ -</b>	<b>\$ (0)</b>	<b>\$ (5)</b>	<b>\$ (11)</b>		
33		Tax Effect of Proforma Interest					\$ 2,961	\$ 6,915		
34		Cash Working Capital Ratio					0.00%	0.00%		
35		<b>Proforma Impact</b>					<b>\$ -</b>	<b>\$ -</b>		
36		Adjusted rate base before proforma adjustments	\$ 2,870,323	\$ 2,870,323	\$ 2,862,667					
37		Plus: Impact of Interest Expense Lag		(7,588)						
38		Plus: Impact of RMA Nos. 1-21		(68)						
39		Plus: Impact Interest Synchronization								
40		Average Rate Base for Interest Synchronization	\$ 2,870,323	\$ 2,862,667	\$ 2,862,667					
41		Weighted cost of long term debt	2.33%	2.33%	2.33%					
42		Pro-forma interest	\$ 66,920	\$ 66,742	\$ 66,742					
43		Less: Per book interest expense		(102,629)	(66,742)					
44		Change to interest expense		\$ (35,887)	\$ -					
45		Adjustment to Maryland Income Tax		\$ 2,961	\$ -					
46		Adjustment to Federal Income Tax		\$ 6,915	\$ -					

Potomac Electric Power Company

Summary of Unadjusted Results and Ratemaking Adjustments for Cash Working Capital  
Fully Forecasted Test Year (FFTY)

Adjustment 23 - Adjustments to Cash Working Capital Allowance

			FFTY - 12 ME Dec 31, 2026							
(1) LINE NO.	(2)	(3) ITEM	(20) REVENUE	(21) O&M	(22) DEPR/ AMORT	(23) OTHER TAXES	(24) SIT	(25) FIT	(26) TOTAL EXPENSE	(27) RATE BASE
1		Maryland Unadjusted Results	\$ 827,603	\$ 264,959	\$ 166,929	\$232,758	\$ 7,073	\$ 6,201	\$ 677,921	\$ 3,023,661
Ratemaking Adjustments										
1	1	Annualization of Case No. 9702 Revenue	(119)	-	-	(0)	(10)	(23)	(33)	-
2	2	Reflection of FERC 898 Software Functionalization	-	-	1,283	-	(106)	(247)	930	3,331
3	3	Removal of Q1 2025 Late Payment Charge Pause	-	-	-	-	-	-	-	-
4	4	Inclusion of Incremental July 2023 Major Storm Costs	-	1,647 *	-	-	(136)	(317)	1,194	5,371
5	5	Reflection of Current Case Costs	-	- *	-	-	-	-	-	-
6	6	Reflection of Battery Energy Storage Pilot	-	- *	62	-	(5)	(12)	45	137
7	7	Reflection of EV Phase I Pilot Costs	-	-	199	-	(16)	(38)	144	649
8	8	Reflection of EV Phase II Pilot Costs	-	-	1,025	100	(93)	(217)	815	4,022
9	9	Reflection of Smart Inverter Pilot Regulatory Asset	-	-	244	-	(20)	(47)	177	449
10	10	Reflection of DRIVE Act Regulatory Asset	-	-	585	-	(48)	(113)	424	890
11	11	Reflection of Supplier Consolidated Billing Costs	-	-	1,211	-	(100)	(233)	878	3,949
12	12A	Reflection of Benning Case No. 9702 Regulatory Asset	-	43 *	-	-	(4)	(8)	31	254
13	12B	Reflection of Benning Forecast Costs	-	88 *	-	-	(7)	(17)	64	608
14	12C	Reflection of Benning Regulatory Asset - Insurance Proceeds	-	(1,575) *	-	-	130	303	(1,141)	(571)
15	13	Reflection of Anacostia Remediation Costs	-	531 *	-	-	(44)	(102)	385	1,731
16	14	Removal of Environmental Activity	-	-	-	-	-	-	-	-
17	15	Removal of SERP Expense	-	(747)	-	-	62	144	(542)	-
18	16	Removal of Outside Contractors/Legal	-	(3)	-	-	0	1	(2)	-
19	17	Removal of Industry Contributions, Membership Fees, and Corporate Jet Cost	-	(1,007)	-	-	83	194	(730)	-
20	18	Exclusion of Executive Incentive Costs	-	(1,844)	-	-	152	355	(1,337)	-
21	19	Exclusion of 50% Employee Activity Costs	-	(361)	-	-	30	70	(262)	-
22	20	Exclusion of Institutional & Promotional Advertising Expense	-	(1,004)	-	-	83	194	(728)	-
23	21	Inclusion of Commission Authorized Interest Expense	-	1,711	-	-	(141)	(330)	1,240	-
24	22	Reflection of Uncollectible Write-Offs	-	652	-	-	(54)	(126)	472	-
25		Proforma Interest Expense							70,981	
26		Cash Working Capital Ratio							-11.34%	
27		<b>Interest Expense Lag</b>							<b>\$ (8,048)</b>	
28		<b>Subtotal Ratemaking Adjustments</b>	<b>\$ (119)</b>	<b>\$ (1,870)</b>	<b>\$ 4,608</b>	<b>\$ 100</b>	<b>\$ (244)</b>	<b>\$ (570)</b>		<b>\$ 3,044,482</b>
29		Less: Non-Cash or Expense Not Lagged in CWC *		(734)						
30		Subtotal Ratemaking Adjustments with CWC Impact	\$ (119)	\$ (2,604)	\$ 4,608	\$ 100	\$ (244)	\$ (570)		
31		Cash Working Capital Ratio		2.61%		2.18%	-2.82%	-2.82%		
32		<b>Proforma Impact to Cash Working Capital of RMA Nos. 1-21</b>	<b>\$ -</b>	<b>\$ (68)</b>	<b>\$ -</b>	<b>\$ 2</b>	<b>\$ 7</b>	<b>\$ 16</b>		
33		Tax Effect of Proforma Interest					\$ 3,586	\$ 8,376		
34		Cash Working Capital Ratio					0.00%	0.00%		
35		<b>Proforma Impact</b>					<b>\$ -</b>	<b>\$ -</b>		
36		Adjusted rate base before proforma adjustments	\$3,044,482	\$3,044,482	\$3,036,391					
37		Plus: Impact of Interest Expense Lag		(8,048)						
38		Plus: Impact of RMA Nos. 1-21		(43)						
39		Plus: Impact Interest Synchronization								
40		Average Rate Base for Interest Synchronization	\$3,044,482	\$3,036,391	\$3,036,391					
41		Weighted cost of long term debt	2.33%	2.33%	2.33%					
42		Pro-forma interest	\$ 70,981	\$ 70,792	\$ 70,792					
43		Less: Per book interest expense		(114,264)	(70,792)					
44		Change to interest expense		\$ (43,472)	\$ -					
45		Adjustment to Maryland Income Tax		\$ 3,586	\$ -					
46		Adjustment to Federal Income Tax		\$ 8,376	\$ -					

Potomac Electric Power Company

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line No.	Adjustment 24 - Tax Effect of Proforma Interest Expense	Historical Test Year <u>12 ME Dec 31, 2024</u>	Bridge Year <u>12 ME Dec 31, 2025</u>	FFTY <u>12 ME Dec 31, 2026</u>
1	<b>Earnings</b>			
2	Ratemaking adjustments to average MD rate base	\$ (6,614)	\$ (141,261)	\$ (125,615)
3	Weighted cost of long term debt	2.33%	2.87%	2.90%
4	Pro-forma interest	\$ (154)	\$ (4,047)	\$ (3,649)
5	Adjustment to Maryland income tax for pro-forma interest expense	13	334	301
6	Adjustment to federal income tax for pro-forma interest expense	30	780	703
7	<b>Total Earnings</b>	<u>\$ (42)</u>	<u>\$ (1,114)</u>	<u>\$ (1,004)</u>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

<u>Line</u>	<u>Adjustment 25 - Adjustment to Operating Revenues</u>	<u>Adjustment</u>
1	<b>Earnings</b>	
2	Opening operating revenues	\$ 795,138
3	Estimated growth in base revenues per year (2024-2026)	2.0%
4	Adjustment to annualize growth in revenues	\$ 843,807
5	Adjustment to annualize billed distribution revenues	\$ 24,692
6	Adjustment to Other Taxes (PSC assessment)	79
7	Adjustment to Maryland Income Tax expense	2,031
8	Adjustment to Federal Income Tax expense	4,742
9	<b>Total Earnings Adjustment</b>	<b><u>\$ 17,840</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

Line	Adjustment 26 - Adjustment to O&M Expenses	Mgmt	Union	Adjustment
1	<b>TOTAL ADJUSTMENT TO O&amp;M Expenses</b>			
2	Adjustment to operations & maintenance for wage increases	\$ 2,877	\$ 1,902	\$ 4,780
3	Adjustment to lobbying, advertisement and related expenses			\$ (29)
4	Adjustment to deferred corrective maintenance work			\$ (5,600)
5	Adjustment to outside services employed			\$ (9,738)
6	Adjustment to overhead maintenance costs			\$ (8,550)
7	<b>TOTAL ADJUSTMENT</b>			<b>\$ (19,137)</b>
8	Adjustment to MD payroll tax expense	258	170	428
9	Adjustment to MD income tax expense			1,544
10	Adjustment to federal income tax expense			\$ 3,605
11	<b>Total Earnings Adjustment</b>			<b><u>\$ 13,561</u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

<b>Line</b>	<b>Adjustment 27 - Removal of rate base</b>	<b>Adjustment</b>
1	<b>Rate Base</b>	
2	<u>Electric Plant In Service</u>	
3	Removal of Rate Base	\$ (96,500)
4	Adjustment to Maryland electric plant in service	<u>\$ (96,500)</u>
5	<u>Accumulated Deferred Income Taxes</u>	
6	Impact on deferred Maryland income tax	\$ 169
7	Impact on deferred Federal income tax	\$ 394
8	Total adjustment to accumulated deferred income taxes	<u>\$ 563</u>
9	<b>Total Rate Base Adjustment</b>	<b><u><u>\$ (95,937)</u></u></b>
10	<b>Earnings</b>	
11	<u>Depreciation Expense</u>	
12	Adjustment to Maryland depreciation expense @ 2.56% composite rate	\$ (2,470)
13	Property tax impact (Est based on TTYCF ratios)	(1,621)
14	<u>Income Taxes</u>	
15	Adjustment to Maryland income tax expense	338
16	Adjustment to Federal income tax expense	788
17	<b>Total Earnings Adjustment</b>	<b><u><u>\$ 2,966</u></u></b>

**Potomac Electric Power Company**

Maryland Distribution  
Ratemaking Adjustment Calculation  
Fully Forecasted Test Year (FFTY)

(Thousands of Dollars)

<u>Line</u>	<u>Adjustment 28 - Removal of NOLC</u>	<u>Adjustment</u>
1	<b>Rate Base</b>	
1	<u>Electric Plant In Service</u>	
2	Removal of Rate Base	\$ (42,408)
3	Adjustment to Maryland electric plant in service	\$ (42,408)
4	<b>Total Rate Base Adjustment</b>	<b><u>\$ (42,408)</u></b>
5	<b>Earnings</b>	
6	Operating expenses	(1,433)
7	<u>Income Taxes</u>	
8	Adjustment to Maryland income tax expense	118
9	Adjustment to Federal income tax expense	276
10	<b>Total Earnings Adjustment</b>	<b><u>\$ 1,039</u></b>

**Potomac Electric Power Company's Application for Adjustments to its Retail Rates  
for the Distribution of Electric Energy**

**Case No. 9820**

**Data Requests and Responses Referenced in the Direct Testimony**

**of Dustin M.J. Madsen**

OPC 6-7

OPC 6-7 Attachment Electronic Only

OPC 6-8

OPC 6-8 Attachment 1 Electronic Only

OPC 6-12

OPC 6-19

OPC 6-20

OPC 6-36

OPC 6-40

OPC 6-40(e) Attachment

OPC 17-6

OPC 17-8

Case 9820 Pepco Public Voluntary Discovery

DR 1

Case 9820 Pepco Public Voluntary Discovery

DR 3

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
RESPONSE TO OPC DATA REQUEST NO.6

QUESTION NO. 7

Please provide an Excel spreadsheet showing the annual O&M costs for the last 10 years, in total, and calculate the average rate of increase over the 10 years. Please also provide the same information for the annual inflation rate over the last 10 years, including a reference to the source of inflation relied upon by the Company.

RESPONSE:

Please see MD 9820 OPC DR 6-7 Attachment Electronic Only. The Company has provided the total Pepco Maryland O&M (both adjusted and unadjusted) for each of the last ten years, based on the 12-month periods available at the Distribution Maryland level. The Company has not historically maintained Pepco Maryland O&M for the same 12-month periods as filed in this case; therefore, the Company has provided the most relevant and available periods to cover the last ten years requested.

SPONSOR: Elizabeth M.D. O'Donnell

OPC DR 6-7

in thousands	12 Months Ending*										10 YR	
	12/31/2016	9/30/2017	12/31/2018	1/31/2019	3/31/2020	3/31/2021	3/31/2022	3/31/2023	3/31/2024	3/31/2025		Yr1 to Yr10
PEP MD Unadjusted O&M	235,149	245,353	251,631	238,896	235,323	226,404	229,625	248,535	255,414	229,581	PEP MD Unadjusted O&M	-0.27%
PEP MD Adjusted O&M	225,126	242,123	243,715	242,863	226,704	215,822	227,380	229,347	246,382	231,212	PEP MD Adjusted O&M	0.30%
Annual Inflation (CPI)**	1.27%	2.06%	2.44%	2.38%	1.94%	1.19%	6.22%	7.40%	3.52%	2.83%	Avg Inflation Rate(CPI growth)	3.10%
<b>Notes:</b>												
* Periods provided represent those that were available at the Pepco Maryland level.												
** *CPI inflation based on S&P Global U.S. Macro 10-Year Baseline Consumer Price Index [2025 April 10 Vintage/Release].												
											<b>Var. To Avg Inflation</b>	
											Unadjusted O&M	-3.36%
											Adjusted O&M	-2.80%

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
RESPONSE TO OPC DATA REQUEST NO.6

QUESTION NO. 8

Please provide a detailed Excel spreadsheet that reconciles each of the adjustments recommended by the Company to the Labor and Payroll costs. Specifically, please include at a minimum:

- (a) A listing of opening FTEs and average salaries at January 1, 2025.
- (b) All changes in position count each year through to the final forecast RY.
- (c) The estimated vacancy rate applied both to actual opening FTEs and that applied going forward.
- (d) The annual increases each year proposed by the Company calculated based on the FTE count.
- (e) Any other adjustments proposed by the Company.
- (f) Final calculated labor and payroll costs reconciled to the both the HTY and FFTY requests.

RESPONSE:

- a./b./c. Please see MD 9820 OPC DR 6-8 Attachment 2 Electronic Only Confidential for position detail counts. Included within the attached are the position detail counts as of 1/1/2025, the updated position detail count as of 11/30/2025 and the approved position detail complement count for 2025. The open positions are shown as the difference between the approved complement and actual positions at a point in time. However, please note that this difference does not necessarily reflect the open budgeted FTEs. The Company reviews approved complements at the department level, determines an appropriate vacancy level, and applies that to the budget. Therefore, the open positions shown are based on the comparison of approved complement to actual positions and do not represent open positions in the budget.
- d. The Company interprets this question as referring to the labor assumption used in developing the Long-Range Plan (LRP). The assumption applied was a 3% annual increase in labor rates.
- e. No other adjustments have been proposed by the Company.
- f. Please see MD 9820 OPC DR 6-8 Attachment 3 for the O&M labor costs for the 2024 HTY, 2025 Bridge year and 2026 FFTY. The Company has not conducted the requested

analysis regarding the labor component of capital expenditures at the Pepco Maryland Distribution level.

SPONSOR: Elizabeth M.D. O'Donnell

Pepco FTE Summary

Responsibility Area	YE Actuals 2024	Actuals 11/30 2025	Complemet vs		Complemet vs		Note 1 Budget YE 2025	Note 1 Complement 2025	Planned YE Vacancy 2025	Note 1 Budget YE 2026	Note 1 Complement 2026	Planned YE Vacancy 2026
			Bud vs Act 11/30 Variance	Actual 11/30 Variance	Bud vs Act 11/30 Vacancy	Actual 11/30 Vacancy						
			2025	2025	2025	2025						
Office of the COO	8	8	-	-	0.00%	0.00%	8	8	0.00%	8	8	0.00%
Customer Operations	206	233	(9)	-	-4.02%	0.00%	224	233	3.86%	224	233	3.86%
Electric Operations	36	38	4	5	9.52%	11.63%	42	43	2.33%	42	43	2.33%
Elec Ops Pepco	617	632	39	65	5.81%	9.33%	671	697	3.73%	671	697	3.73%
Government, Regulatory, & Ext Affairs	25	28	8	9	22.22%	24.32%	36	37	2.70%	36	37	2.70%
Projects & Contracts	78	73	11	8	13.10%	9.88%	84	81	-3.70%	84	81	-3.70%
Transmission and Substation	260	271	5	9	1.81%	3.21%	276	280	1.43%	276	280	1.43%
Technical Services	32	34	(1)	-	-3.03%	0.00%	33	34	2.94%	33	34	2.94%
All Other (Supply Chain)	35	36	1	2	2.70%	5.26%	37	38	2.63%	37	38	2.63%
BSC Embedded (Legal)	2	2	-	-	0.00%	0.00%	2	2	0.00%	2	2	0.00%
<b>Total Pepco</b>	<b>1,299</b>	<b>1,355</b>	<b>58</b>	<b>98</b>	<b>4.10%</b>	<b>6.74%</b>	<b>1,413</b>	<b>1,453</b>	<b>2.75%</b>	<b>1,413</b>	<b>1,453</b>	<b>2.75%</b>

Note 1: Complement represents the total approved FTEs while the budget count represents the number of positions net of the planned vacancy.

POTOMAC ELECTRIC POWER COMPANY  
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RESPONSE TO OPC DATA REQUEST NO.6

QUESTION NO. 12

Refer to the Testimony of Witness O'Donnell at page 25, in relation to deferred work, please quantify in detail all planned work that was deferred and identify where that planned work is expected to be performed in either 2025 or 2026. Additionally, please identify and quantify any further deferred work from 2025 to 2026, quantify the amounts deferred and confirm within which accounts those costs are recorded.

RESPONSE:

The Company interprets this question as a request for analysis on deferred corrective maintenance projects on a year-over-year basis. The Company had an estimated, allocated budget for O&M corrective maintenance work of \$33.4M for 2024. Actual O&M corrective maintenance expenses in 2024 were \$27.8M. To clarify, the Company does not defer any priority corrective maintenance work due to immediate severity or safety concerns that would interfere with the Company's ability to provide safe and reliable service. The requested analysis on deferrals has not been performed on an individual action, project or program basis.

The deferral of planned work is expected to result in an increase in costs for emergent repairs. To remain committed to long-term cost discipline, the Company must prioritize corrective maintenance work required to restore service to customers safely.

SPONSOR: Elizabeth M.D. O'Donnell and Samuel Williams

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
RESPONSE TO OPC DATA REQUEST NO.6

QUESTION NO. 19

Refer to the direct testimony of Witness Leming (Part II) at page 11, please provide a reconciliation of the actual to approved minor storms costs for the last five years.

RESPONSE:

The requested analysis has not been performed. The Commission's approval of the electric distribution company's revenue requirement establishes the total amount the utility is authorized to recover from customers. It does not prescribe or approve individual cost components within that revenue requirement. This approach provides the utility with necessary flexibility to manage its operations and allocate resources efficiently, while ensuring compliance with regulatory standards. See table below for actual minor storm costs for the last five years.

Year	Minor Storms
2020	2,602,902
2021	6,070,930
2022	13,358,018
2023	3,312,470
2024	3,049,173

SPONSOR: Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
RESPONSE TO OPC DATA REQUEST NO.6

QUESTION NO. 20

Refer to the direct testimony of Witness Leming (Part II) at page 11, please provide any precedent either from Maryland or another jurisdiction where a similar minor storm costs deferral has been approved.

RESPONSE:

Pepco is unaware of any Maryland Commission decisions allowing deferral of minor storm costs. Pepco has not conducted a review of other jurisdictions to determine whether or not those jurisdictions allow “similar” minor storm costs deferral.

SPONSOR: Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
RESPONSE TO OPC DATA REQUEST NO.6

QUESTION NO. 36

Please prepare a table comparing the actual and approved reliability capital expenditures by year for the last five years, as well as for 2025 and 2026, as well as the actual and forecast SAIDI and SAIFI metrics. If the company had previously budgeted (or approved) SAIDI and SAIFI metrics for historical years, please also provide that information.

RESPONSE:

For the table of approved reliability capital expenditures, please refer to page 23 of Pepco’s 2021–2023 Recommended Reliability Standards (Maillog No. 220588) and page 27 of Pepco’s 2024–2027 Recommended Reliability Standards (Maillog No. 239387).

Actual vs Forecasted Reliability				
	Actual		Forecasted (See Reliability Standards Reports)	
Year	SAIFI	SAIDI	SAIFI	SAIDI
2020	0.65	54	0.76	77
2021	0.58	55	0.74	71
2022	0.68	56	0.73	68
2023	0.52	46	0.71	65
2024	0.52	48	0.66	61
2025	-	-	0.59	57
2026	-	-	0.55	55

SPONSOR: Taiwo O. Alo

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
RESPONSE TO OPC DATA REQUEST NO.6

QUESTION NO. 40

Regarding the Company's proposal (Witness Leming (Part II)) to adjust its ratemaking treatment for net operating loss carryover impacts, please provide the following information:

- (a) Any ruling from the IRS received to date.
- (b) If no ruling has been received, provide the Companies' anticipated date of receipt of a ruling, and any other communications received from the IRS.
- (c) Please provide all detailed calculations supporting the Company's proposed adjustments to accumulated deferred income taxes related to NOLCs and the income tax regulatory liability included in rate base to comply with the "normalization" provisions under federal tax law, including:
  - (i) Workpapers in Excel (formulae intact) that derive the total change in income taxes flowed to Pepco by year resulting from a change in the recognition of the NOLC;
  - (ii) Workpapers in Excel (formulae intact) that derive the change in ADIT to incorporate the changes in the recognition of the NOLC;
  - (iii) Workpapers in Excel (formulae intact) that derive the DTAs used to incorporate changes in the recognition of the NOLC;
  - (iv) Workpapers that derive changes to Operating Income necessary to accommodate the changes in the recognition of the NOLC.
- (d) Indicate the amount of depreciation deductions and taxable income for federal income tax purposes in each period for which a change in recovery of the NOLC was deemed necessary.
- (e) Of the \$133 million FTY revenue requirement and the \$142 million TTYCF revenue requirement, indicate the amount that relates to changes in the recognition of the NOLC.
- (f) Indicate the amount of depreciation deductions and taxable income for federal income tax purposes in each period for which a change in recovery of the NOLC was deemed necessary.
- (g) Please explain in detail how the accelerated deduction of tax losses by the consolidated entity benefits Pepco's customers.

- (h) Indicate the amount of depreciation deductions and taxable income for federal income tax purposes in each period for which a change in recovery of the NOLC was deemed necessary.
- (i) Please confirm that, when a change in regulatory treatment for collecting taxes is proposed, it is mandatory that the transitional impacts of that change be fully reflected through the ADIT and regulatory tax liability. If not confirmed, please fully explain why not, and also explain how such a result would ensure that customers only pay for the actual taxes paid by the Company to the IRS.

RESPONSE:

- a. As of the date of this response, Pepco has not received a ruling from the IRS on its PLR request related to the proper application of the “normalization” rules with respect to tax net operating loss carryforwards (“NOLC”).
- b. Typically, the IRS issues rulings within six to nine months of filing the private letter ruling request. Pepco has not received any formal communication from the IRS except for acknowledgement of receipt of the private letter ruling request.
- c. Refer to MD 9820 OPC DR 6-40 Attachment Confidential for supporting calculations of the NOLC adjustment.
- d. Refer to attachment in response to subpart c.
- e. [Refer to MD 9820 OPC DR 6-40 \(e\)](#)
- f. Refer to response in subpart d.
- g. For ratemaking purposes, Pepco calculates its regulatory tax expense by reference to the receipts and expenditures that are recognized for jurisdictional ratemaking purposes by FERC and the MDPSC. This methodology looks beneath the single consolidated tax liability and analyzes each item of income and deduction used to determine the Affiliated Group’s tax liability to determine the income and deductions attributable to each utility service. It then allocates to each jurisdictional service those items which were generated by providing that service.

Pepco includes all used and useful public utility property in rate base, calculates depreciation expense thereon using a straight-line method, depreciates such property for federal income tax purposes using accelerated depreciation as permitted by the Modified Accelerated Cost Recovery System (“MACRS”), and makes an adjustment to the reserve for ADIT at the federal statutory tax rate to reflect the difference in tax liability attributable to the use of different depreciation methods for book and tax purposes. All of these calculations are done without regard to the property, tax attributes, or separate tax liability, of other members of the Affiliated Group. It also is done without regard to any items of Pepco that are non-jurisdictional with respect to the rates it is determined.

- h. Refer to response in subpart d.
- i. On June 28, 2024, the Internal Revenue Service (“IRS”) published a series of private letter rulings<sup>1</sup> (“PLR”) requested by another taxpayer (“Taxpayer”) that provides guidance with respect to the application of the “normalization” rules and the proper treatment of income tax benefits associated with tax net operating losses among affiliates within a consolidated group for ratemaking purposes.

Although a PLR can only be relied upon by the taxpayer that received it, it is instructive to other taxpayers as to the IRS’ point of view on a subject matter.

Given Pepco’s fact pattern is identical to the one described in the PLRs, pursuant to Section 3.01(3) of IRS Revenue Procedure 2017-47, Pepco is required to change its methodology and take corrective action at the “next available opportunity” to comply with the “normalization” provisions or be subject to the penalty for a “normalization” violation.

For ratemaking purposes, adopting the revised methodology prescribed in the PLRs requires Pepco to make two adjustments that will reduce: (1) accumulated deferred income taxes (“ADIT”); and (2) the income tax regulatory liability included in rate base. Each of these adjustments will result in an increase to rate base.

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<sup>1</sup>PLR 2024426002, 202426003, 20246004

(Thousands of Dollars)

	Schedule (RTL)-1	Schedule (CN)-1
	FFTY	TTYCF
Rate Base NOLC Impact	42,408	51,509
Operating Expense -NOLC Impact	1,433	1,433
Interest Sync Adjustment		
Rate Base Impact	42,408	51,509
Weighted Cost of Long-Term Debt	2.48%	2.43%
Pro Forma Interest on Average Rate Base	1,054	1,254
SIT Pro Forma Interest	(87)	(103)
FIT Pro Forma Interest	(203)	(242)
Operating Expense Net of Interest Sync Adjustment	1,230	1,192
Revenue Requirement	6,399	7,316

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
RESPONSE TO OPC DATA REQUEST NO.8

QUESTION NO. 3

Refer to Mr. Leming's direct testimony, Schedule (RTL)-1 at 13 and to Mr. Nelson's direct testimony, Schedule (CN)-1 at 14, which addresses the current rate case cost estimate.

- (a) Provide the actual rate case costs incurred for which the Commission awarded recovery in Case No. 9655 and 9702.
- (b) Detail the analysis underlying the company's \$1.295 million rate case cost estimate, including labor hours, hourly labor rates (actual or estimated), consultant fees, etc... Provide any workpapers or schedules that support the company's analysis.
- (c) Approximate the amount of the cost estimate attributable to the development and litigation of the FFTY proposal and, separately, the amount of the cost estimate attributable for the development and litigation of the TTYCF.

RESPONSE:

- a) Case No. 9655: Not Applicable – Estimated outside counsel and rate case preparation costs were included in calendar year 2020, which covered portions of the historical test year and bridge year as O&M expense, and as such are not part of the revenue requirement in the MYP period.

Case No. 9702: See MD 9820 OPC DR 8-3 Attachment A, which reflects forecast rate case expenses approved in RMA 11 as an uncontested adjustment in that proceeding.

- b) Please see MD 9820 OPC DR 8-3 Attachment B CONFIDENTIAL.
- c) The requested analysis has not been performed.

SPONSOR: Robert T. Leming, Conor Nelson

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
RESPONSE TO OPC DATA REQUEST NO.17

QUESTION NO. 6

Refer to the company's response to OPC DR 3-3.

- (a) Confirm whether the charges to Account 426.1 exclude costs associated with the management of employee volunteer programs, charitable giving programs, sponsorships, and other programs.
- (b) If the answer to subpart (a) is yes, identify the FERC account to which such internal costs are charged and identify all such costs and the charitable activities such costs support for the year ending on December 31, 2024 and, if currently available, the year ending on December 31, 2025. If such information cannot be provided, please explain why not.

RESPONSE:

- a. Confirmed.
- b. The costs allocated from PHISCO associated with managing PHI charitable contributions, volunteer programs and sponsorships are charged to FERC 426.5. All the expenses charged to that FERC account are below the line and excluded from the Company's revenue requirement.

As a standard practice, the Company classifies these costs as below-the-line (BTL) and accounts for them accordingly for PHISCO purposes. During its review of actuals, the Company identified approximately \$29 thousand allocated from EBSC that had been inadvertently recorded to FERC 923 and included in the cost of service. These costs will be removed from the TTYCF revenue requirement in the Company's rebuttal testimony. This correction does not affect the FFTY revenue requirement, as all below-the-line costs were correctly excluded from the FFTY projections.

SPONSOR: Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
RESPONSE TO OPC DATA REQUEST NO.17

QUESTION NO. 8

Refer to the company's response to DRS 3-6, 3-7, and 3-9. Expenses listed under accounts 909 and 930.1 appear to only reflect costs associated with external services. Does the company account for the costs of internal employee time spent developing and approving these campaigns? If yes, explain how the company removes the portion of employee compensation that supports promotional or institutional advertising and marketing and identify the ratemaking adjustments where such expenses have been removed.

RESPONSE:

All costs provided are associated with external vendors. The Company does not separately track the costs of internal employee time spent developing and approving these campaigns. The employee time associated with this activity—and the resulting internal labor costs included in the Company's cost of service—do not represent an incremental expense. These labor functions would have occurred, and the related costs would have been incurred, as part of the Company's normal utility operations irrespective of the specific event or program.

SPONSOR: Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
VOLUNTARY DISCOVERY DATA REQUEST NO. 1

QUESTION NO. 1

Provide all workpapers in Excel with all formulae intact for the testimony and schedules of Company Witness Leming, both Part I and Part II.

RESPONSE:

Please refer to MD 9820 Voluntary DR 1-1 Attachment A Electronic Only for workpapers supporting Schedule (RTL)-1.

Please refer to MD 9820 Voluntary DR 1-1 Attachment B Electronic Only for workpapers supporting Schedule (RTL)-2.

Please refer to MD 9820 Voluntary DR 1-1 Attachment C Electronic Only for workpapers supporting Schedule (RTL)-3.

SPONSOR: Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
VOLUNTARY DISCOVERY DATA REQUEST NO. 1

QUESTION NO. 2

Provide all workpapers in Excel with all formulae intact for the testimony and schedules of Company Witness O'Donnell.

RESPONSE:

Please refer to MD 9820 Voluntary DR 1-2 Attachment CONFIDENTIAL Electronic Only for workpapers supporting Schedule (EMDO)-2.

SPONSOR: Elizabeth M.D. O'Donnell

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
VOLUNTARY DISCOVERY DATA REQUEST NO. 1

QUESTION NO. 3

Provide all workpapers in Excel with all formulae intact for the testimony and schedules of Company Witness Nelson.

RESPONSE:

Please refer to MD 9820 Voluntary DR 1-3 Attachment A Electronic Only for workpapers supporting Schedule (CN)-1.

Please refer to MD 9820 Voluntary DR 1-3 Attachment B Electronic Only for workpapers supporting Schedule (CN)-2.

SPONSOR: Conor Nelson

POTOMAC ELECTRIC POWER COMPANY  
MARYLAND CASE NO. 9820  
VOLUNTARY DISCOVERY DATA REQUEST NO. 3

QUESTION NO. 1

Provide all workpapers in Excel with all formulae intact for the Supplemental Direct testimony and schedules of Company Witness Nelson.

RESPONSE:

Please see 9820 Voluntary DR 3-1 Attachment A Electronic - Schedule (CN-SD)-1 for Excel workpaper supporting Schedule (CN-SD)-1

Please see 9820 Voluntary DR 3-1 Attachment B Electronic - Schedule (CN-SD)-2 for Excel workpaper supporting Schedule (CN-SD)-1

Please see 9820 Voluntary DR 3-1 Attachment C - TTYCF JCOS for Excel workpapers supporting the Update-to-Actuals (12+0) TTYCF Jurisdictional Cost of Service.

Please see Supporting Data I.N Attachment A1 (thru A38) 12.18.25 Update for Excel workpapers supporting the Update-to-Actuals (12+0) Ratemaking Adjustments

SPONSOR: Conor Nelson